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CPA

October 14, 2005

William A. Bonnet
Vice President
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The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

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PUBLIC UTILITIES
COMMISSION

Dear Commissioners:

Subject: Comments Relating to the RPS Technical Paper

Attached are HECO's comments to the RPS Technical Paper, *Planned Computer Simulations Facilitating the Analysis of Proposals for Implementing the Renewable Portfolio Standards Provision in Hawaii*, dated September 23, 2005.

If you have any questions regarding this matter, please contact Dean Matsuura at 543-4622.

Sincerely,

William A. Bonnet

Attachment

cc: Division of Consumer Advocacy

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

Hawaiian Electric Company, Inc. Comments on Economists Incorporated's "Planned Computer Simulations Facilitating the Analysis of Proposals for Implementing the Renewable Portfolio Standard Provision in Hawaii" dated September 23, 2005

Act 95, S.L.H. 2004, Relating to Renewable Portfolio Standards Technical Workshop October 5, 2005

October 14, 2005

These comments are respectfully submitted on behalf of Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO") (collectively referred to as "the HECO Utilities" or "the Companies").

As requested by the Commission at the October 5, 2005 Technical Workshop, the Companies are submitting their preliminary comments and questions regarding Economists Incorporated's ("EI") technical paper "Planned Computer Simulations Facilitating the Analysis of Proposals for Implementing the Renewable Portfolio Standard Provision in Hawaii", dated September 23, 2005. As discussed at the Technical Workshop, the Companies seek clarification on a number of issues with respect to Incentive Regulation Mechanisms and Modeling Assumptions. The

Companies questions and comments follow, and pending the responses, additional information and computer simulation modeling results to be provided by EI the Companies may have follow-up questions or comments.

I. INCENTIVE REGULATION MECHANISMS

What IR mechanisms should be evaluated?

In general, a key objective of the market model simulations is to help evaluate the impact and effectiveness of various incentive regulation (IR) mechanisms.

Substantial written comments were provided by the workshop participants on the 7 IR mechanisms described in the Second Concept Paper, and there was substantial discussion of the 7 mechanisms in the first two days of the workshop. There were concerns raised with respect to all of the mechanisms, including concerns with respect to authority to implement some of the mechanisms.

At the workshop, HECO's RPS consultant, Edward L. Selgrade, Esq., outlined an Equity Adder IR Mechanism that could meet all of the requirements of Act 95. (Mr. Selgrade's background and experience are included in Exhibit A.) A more detailed description of such an IR mechanism is provided in Exhibit B.

HECO urges the Commission and EI to consider IR mechanisms such as the Equity Adder mechanism described in Exhibit B.

How Will the IR mechanisms be evaluated?

It appears that the outputs of the model will be rate impacts and utility financial impacts.

As HECO noted at the modeling workshop, if the assumption is that the amounts of renewables added to utility systems are the same regardless of the IR mechanism utilized, then the only impacts of the mechanisms will be positive or negative impacts on utility rates and utility financials. Positive incentive mechanisms (the "carrot" approach referred to at the workshop) will be "modeled" to negatively impact rates, because they will be "assumed" to be a cost without an offsetting benefit in terms of increasing the amount of renewables added or reducing the cost of the renewables added.

It is difficult to model the positive effect of positive incentives, because generally there is no cause and effect empirical data base to use in modeling the effect of the incentives. Nonetheless, it has been broadly recognized that positive incentives have positive impact on performance. Thus, the assumption that incentives will <u>not</u> have positive impacts clearly would be erroneous.

As pointed out in the Second Concept Paper (SCR), Nevada has an aggressive RPS law. As EI noted, however, the early performance of the Nevada RPS "is generally disappointing", and "[o]nly a small quantity of electricity statewide has been generated by new renewable energy systems." (SCR, page 18, ¶45.)

As a result, on November 4, 2004, the Nevada Renewable Energy and Energy Conservation Task Force held a workshop on how to improve the Nevada RPS. (SCR, page 19, ¶47.) The discussion and recommendations are summarized in the report cited in the Second Concept Paper (page 18, footnote 82).[1]

The inclusion of a penalty mechanism (the "stick" approach referred to at the Hawaii workshop) in the Nevada RPS law apparently has <u>not</u> resulted in the achievement of the RPS:

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1 Kevin Porter, Robert Grace, and Ryan Wiser, Summary of Recommendations: Legislative and Regulatory Actions to Consider For Ensuring the Long-Term Effectiveness of the Nevada Renewable Portfolio Standard (Draft), December 3, 2004 available at http://energy.state.nv.us/. (Nevada Draft Report).

> The Nevada RPS statute gives the PUCN the authority to impose a penalty on a Nevada utility for failing to comply with the Nevada RPS, unless the utility successfully seeks an RPS waiver for that year. So far, the PUCN has granted all utility petitions for waivers, and has yet to impose penalties for RPS non-compliance. The PUCN, however, may impose a penalty of at least the difference in price between the market price of electricity and the price of the renewable energy generation. Nevada utilities may not recover such penalties in rates or in any other way from retail customers. The resulting environment is not particularly conducive to getting renewable generation built: if the utilities contract and fail, nothing will result (the RPS is simply not met); if the utilities fail to contract, they may be painted as bad actors and subjected to penalties, even if the fault lies elsewhere for their lack of success.

(Nevada Draft Report, page 4.)

Among the recommendations resulting from the workshop was a proposal to offer positive incentives to utilities. "Under this option, utilities would receive an adder to their rate of return or other financial incentive for undertaking actions supporting compliance with the Nevada RPS." (Nevada Draft Report, page 3.) According to the draft report, implementing such incentives would serve to align utility and public policy incentives more effectively, and would result in renewable energy generation being financed and built more effectively. (Nevada Draft Report, page 4.)

The question is often asked why an incentive mechanism is appropriate to encourage a utility to achieve utility objectives. For example, in Docket No. 04-0113, Mr. Daniel Violette, Principal, Summit Blue Consulting[2], was asked to respond to the following information request (CA-IR-320.a):

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[2] Mr. Violette's background and experience are summarized in Exhibit C.

Given HECO's need to add new resources to meet strong load growth, why does Mr. Violette believe the Company must receive positive incentives beyond direct cost recovery of the Commission approved DSM programs to encourage implementation of cost-effective DSM programs?

His response was as follows:

The witness' testimony is that it is a matter of good public and regulatory policy to provide positive incentives so that investments in suitable and effective demand-side management programs are at least as attractive to the utility as investments in supply-side options. Load growth, coupled with the time required to implement new supply-side resources, provide an incentive to a utility to pursue demand-side resources, at least in the short-run. But that does not mean that requiring the utility to accept uncompensated risks as its "reward" for meeting its service obligation is good public or regulatory policy. That would be comparable to arguing that a utility should not be compensated for costs incurred in restoring its system after a natural catastrophe, because the utility needs to restore its system anyway in order to provide service. In the longer term, the "message" conveyed to the utility would be that it should focus its future efforts on the supply-side of the equation.

The history of the utility industry up until the 1990's was one of building capital intensive supply-side units to meet load growth. These investments were rate-based and a return was earned on them. The advent of better and more cost-effective energy efficiency measures in the late 1980s and 1990s, meant that some load growth could be cost-effectively met through the implementation of utility-sponsored conservation programs. This is similar to building a conservation-based power plant. The utility has to develop infrastructure, design a product/program, put in place a marketing plan, and build a fulfillment strategy/capability. In essence, the allocation of component costs for an energy efficiency program may differ from that of more traditional supply-side alternatives; but, the energy efficiency program, like the supply-side alternatives, should also be provided with the opportunity to earn a return on investment so that 1) investments in suitable and effective demand-side management programs are at least as attractive to the utility as investments in supply-side options, and 2) the utility can fulfill its financial responsibility to its investors.

Mr. John Rowe, currently the CEO of Exelon (parent company to ComEd and PECO), wrote in the preface to the landmark National Association of Regulatory Commissioners (NARUC) publication "Profits and Progress through Least-Cost Planning," David Moskovitz, NARUC, November 1989 that:

> ***Conservation, which for now appears the least-cost component of energy supply plans, must be the most profitable component.*** I have had the privilege of leading two utilities with outstanding reputations for conservation efforts. But, neither has exhausted the conservation

> potential which commissioners and environmental groups believe exists. Incentive measures which are genuinely attractive to utilities provide the necessary means to develop the real potential, whatever it may be. ***Such incentive measures are equally necessary to obtain public credibility for least-cost planning***. (emphasis added)

Part of the rationale behind the provision of positive incentives for implementation of cost-effective DSM programs stems from the alternative, i.e., a command and control approach imposed by the PUC. Given that traditional rate-of-return regulation provides incentives that discourage utilities from pursuing cost-effective DSM, one solution to this problem can be increased oversight by the Hawaii PUC and a greater reliance on command and control regulation. However, most PUCs have limited resources to monitor utility behavior, and the adoption of incentives that re-enforce the desired utility behavior without the imposition of intense regulatory oversight (due to having to overcome the negative financial outcomes to the utility that can result from DSM) is another desirable outcome. Finally, successful DSM depends on the innovation and commitment of the utility and this is best accomplished through appropriate shareholder incentives rather than the use of regulatory mandates requiring commission oversight.

He was also asked to respond to the following question (CA-IR-320.c):

Is Mr. Violette saying that, absent DSM incentives, HECO likely will choose to make more costly and perhaps riskier supply-side investments?

His response was as follows:

The witness is unable to speculate about the decisions that HECO management might make under different possible futures that might entail different financial risks for stockholders and ratepayers. A number of factors must be considered when making decisions regarding new investments meant to meet future loads. If the investment in a particular alternative bears an uncompensated financial risk for the utility, it might not be in the interest of ratepayers for the utility to make that investment even if net present value investment analyses show it to be the "least-cost" investment (ignoring the impact of the uncompensated risk on the cost of capital). For example, if aggressive DSM results in lower revenues for the utility and can lead to changes in the financial circumstances of the utility, its stock price can be impacted as well as its credit ratings. In turn, this will have an impact on ratepayers.

Several examples can be cited concerning how financial incentives have impacted the investment in DSM by utilities:

First, there is the situation that occurred in the Northwest where an attempt to implement a regional least-cost plan was stymied by a disagreement over appropriate incentives:

Snohomish PUD Slashes Conservation
The Snohomish County Public Utility District, an electric utility in Everett, Washington, unexpectedly dropped its conservation plans for 1994 after failing to negotiate a new contract with Bonneville Power Administration (BPA) for a "conservation power plant." A chief reason given for the decision was lost revenue (emphasis added). The move has created an ironic situation for Snohomish, according to Al Aldrich, the utility's director of communications and service development. "For 1993, the district has the largest conservation program budget it has had since 1983, about $18 million, but we've also given layoff notices to 41 employees out of our total conservation staff of 61." Layoffs are scheduled to take effect between June and December as existing contracts are completed and programs slow down in early 1994, when conservation activity will reach its lowest level since the district began such programs. (Source: Home Energy Magazine Online May/June 1993)

As a public utility district, the customers and owners are the same and there is no reason not to take the most economic course of action. The article goes on to state that "Although the contract would have only cost the utility $2 million of the net operating cost of the $186 million program, at its peak the contract would have cost the district an additional $8 million in annual lost revenue..." As a result, the utility decided not to undertake the conservation investment. This is an important example in that the welfare of the member-owners of the PUD coincides with that of its customers. Without being made whole for its investment in DSM, the utility would not undertake that investment.

In addition, there is the statement by Mr. John Rowe (formerly CEO of the New England Electric System and now CEO of Exelon) where he says of requirements to invest in DSM:

> The utility is being told to sell less of its chosen product and to provide a service...It must do this without being offered any additional profit and often without being assured of cost recovery. Slowly, lashed by the misused slogan 'duty to serve,' utilities respond, but the results are credible to no one." (Source: Foreward to "Profits & Progress through Least-Cost Planning," published by the National Association of Regulatory Utility Commissioners, November 1989).

Mr. Rowe's statement that utilities are -- "lashed by the misused slogan 'duty to serve'..the results are credible to no one" -- provides the strong signal that this utility CEO, without directly pointing the finger at other CEOs, indicates that investments in energy efficiency may not approach optimal levels without positive incentives.

Also, one can look at the U.S. Energy Information Administration's data on recorded investment in DSM to see that the downward trend industry-wide in DSM that accompanied the changes in incentives of the late 1990's and early 2000's. It is exactly this dip that is in the interest of HECO and its ratepayers to avoid.

Finally, the recent report on Hawaii Energy Utility Regulation and Taxation, Hawaii Energy Policy Forum, July 2003, as quoted on page 27 of HECO T-12, suggests concerns about how aggressively utility management might pursue DSM if the current financial mechanisms are ended. The authors stated in this report:

> Unless these financial mechanisms are replaced with some form of mandate or alternative incentives, the current DSM programs are in serious jeopardy....The mechanisms being terminated quietly by the PUC were previously established by several years of collaborative efforts by Hawaii's energy sector stakeholders.

In summary, while it is not possible to speculate what actions HECO might take, there is evidence that incentives make a difference in the level of commitment to investments in energy efficiency. Working out a set of financial mechanisms whereby the utilities least cost plan is also their most profitable plan makes good sense. Appropriate alignment of incentives is simply good public policy.

In the early 1990's, several regulatory commissions that strongly supported DSM recognized the superiority of the "incentive" approach adopted in Hawaii to the "command and control" approach. In the "command and control" approach, the PUC specifies exactly what the utility should do. The PUC then monitors closely subsequent actions for compliance with the PUC directive. If the utility does not follow adequately the PUC order, the PUC, in subsequent proceedings, can penalize the utility.

For example, the Massachusetts Department of Public Utilities ("DPU") took the position that utilities under its jurisdictions were mandated to aggressively pursue DSM, but allowed the recovery of lost margins and shareholder incentives as well. See, e.g., Re Western Massachusetts Electric Co., 114 P.U.R.4th 239, 273, 279 285 (Mass. DPU 1990).

The California Public Utilities Commission ("CPUC") examined this question at some length in the extensive proceedings that it conducted on the subject of shareholder incentives in the early 1990's.

As part of a proceeding initiated in 1991 to establish rules and procedures for utility DSM, the CPUC directed that a report be submitted on the effectiveness of the shareholder incentive mechanisms it had approved in 1990. In the 1993 report prepared by the Wisconsin Energy Conservation Corporation ("WECC"), WECC recommended that DSM shareholder incentives become a permanent feature of the regulatory framework:

> [I]f a sustained, effective DSM effort by a utility is desired to attain some or all of the societal benefits produced by increased DSM, then shareholder incentives are necessary and appropriate to increase the private value of DSM to a utility by bringing that value more in line with its societal value. Where successful DSM efforts will depend on the judgment and enthusiasm of the provider and the encouragement of innovation, shareholder incentives are a preferred regulatory scheme compared to the use of regulatory mandates by themselves.

Re Rules and Procedures Governing Utility Demand-Side Management, 51 C.P.U.C.2d 371, 1993 Cal. PUC LEXIS 675 (1993) at *16-*17.

WECC also identified explicit benefits of the incentive approach: "Compared to the pre-incentive period, WECC observe significant improvements in the recruitment of high quality, experienced and motivated personnel to work on DSM. WECC's analysis also indicates that incentives have led to the perception of DSM as a profit center within the utilities, as opposed to "a necessary evil that must be done to appease regulators." 1993 Cal. PUC LEXIS 675 at *37.

DSM program advocates, and public utility commissions in other jurisdictions, have recognized that there are limits to the efficacy of the "command and control" approach.

For example, the Vermont Public Service Board recognized the difficulty in ordering a utility to take actions inconsistent with the welfare of its shareholders:

> Any effort to implement least-cost utility planning must recognize that implementation of demand-side measures requires a workable partnership between the utilities and their customers, supported by the regulatory framework within which they operate. To maximize their effectiveness, demand-side programs must be carefully crafted, creatively marketed, and intelligently monitored. These characteristics cannot be achieved by regulatory fiat alone, and are not likely to be achieved at all if utilities are financially penalized for succeeding in lowering their sales.

Re Least-Cost Investments, Energy Efficiency, Conservation and Management of Demand for Energy, 111 P.U.R.4th 427, 435 (Vt. PSB 1990).

The Colorado PUC also pointed out problems with the "command and control" approach:

> One solution to this problem [financial incentives that inhibit utilities from pursuing DSM] would be increased oversight with greater reliance on command and control regulation. Given the limited resources available to monitor utility behavior in Colorado, as well as our preference to adopt a solution that positively reinforces the desired utility behavior without the imposition of constant regulatory oversight, this commission prefers to address the problem through regulatory reform.

Re Public Service Company of Colorado, 139 P.U.R.4th 397, 403 (Col. PUC 1993).

II. MODELING ASSUMPTIONS

A. Modeling Considerations

See Exhibit D for the Companies comments and questions on the production simulation and other modeling considerations.

B. Financial Assumptions

Reference: Paragraphs 23 and 25, bullet 9: Discount Rate

The technical paper indicates that a discount rate of 8.42% will be used, based on the data submitted to the Commission by HECO. From 2002 to 2004, 8.42% was the weighted average after-tax cost of capital assumption which HECO used for long-term forecast purposes. Use of other discount rates was discussed at the technical meeting held on October 5, 2005.

In prior rulings relating to the evaluation of purchase power agreements, the Commission has ordered the use of the utility weighted average after-tax cost of capital to present value the cost of purchased power and the utility's avoided cost and compare the present values of the two. [See Docket No. 6378, For approval of the Kalaeloa Power Purchase Contract, Interim CT Lease, and related costs, to include costs in its Fuel Clause and for declaratory ruling as to H. R. S. §269-1, Decision and Order No. 10369 dated October 16, 1989, p. 66 and Docket No. 6177, For Approval of AES Power Purchase Contract, related costs, and Approval to include costs in its Fuel Clause, Decision and Order No. 10448 dated December 29, 1989, p. 19.] HECO proposes that the utility weighted average after-tax cost of capital based on the cost of capital assumptions used in the financial projections should be one of the discount rates used in doing present value calculations. HECO does not object to present value analysis sensitivities using other discount rates in addition to a calculation based on the weighted average after-tax utility costs of capital.

Reference: Paragraphs 95 and 101, bullet 2: Representation of rate of return regulation

The technical paper indicates that "In the planned simulations, the CER may be used to represent the utility's capability for capital attraction and investment through a financial analysis and a comparison of generation alternatives." A footnote indicates "For a view that '..each utility's capital structure is a corporate business decisions' and that '..the existing capital structure should be used,' see Datta, *Ibid* at 24." The paper further states that "The rate case process may be represented through a repetition of the cycle, for example, every five years."

It is not clear from the discussion whether the simulations will be designed to maintain the financial integrity of the utility or whether the financial integrity of the utility will be assessed as a result of the various embedded modeling assumptions. There are numerous potential measures of financial integrity which can be considered. In its recent rate case, HECO discusses and analyzes three measures: 1) Funds from Operations Interest Coverage, 2) Funds from Operations/Average Total Debt and 3) Total Debt/Total Capital. [See Docket No. 04-0113, HECO T-21, pp. 25-29, HECO-2112 and HECO-2116.]

If the intent of the simulation design is to maintain the financial integrity of the utility, the utility capital structure decisions and rate case timing used in the modeling should be determined based on target financial measures. For example, if the goal is to maintain the utility's creditworthiness and its credit rating by Standard & Poors of BBB+, and assuming maintenance of its current business risk profile of 5, the utility would target maintaining ratios within the BBB+ guidelines established by S&P (See Docket No. 04-0113, HECO-2112. Debt issuance could be timed and sized to stay within the Total Debt (including imputed debt)/Total Equity ratio. Rate case timing (with consideration for regulatory lag) could be determined based on the utility's ability to maintain Funds from Operations Interest Coverage and Funds from Operations/Total Debt (including imputed debt) ratios. Imputed debt or capital lease treatment of purchase power agreements should be considered in assessing the utility's creditworthiness. HECO's recent rate case, Docket No. 04-0113, included discussion of imputed debt in HECO-T-21 pp. 26-27 and HECO-2111 and lease accounting for purchase power agreements in HECO-T-21 pp. 18-19 and HECO-2113.

On the other hand, if the intent of the modeling is to assess the financial integrity of the utility as a result of the various embedded modeling assumptions, certain assumptions may distort the financial assessment. For example, assuming rate cases every 5 years may result in unrealistically poor financial results in non-rate case years.

C. <u>Fuel Forecast</u>

The goal should be to use an ***objective*** forecast, based on sound analysis of market fundamentals as viewed by energy experts, and to use high and low sensitivity scenarios that bracket the reasonably expected outcomes, given the cyclical experience with oil prices, and the need to forecast for a 20-30 year planning period.

Due to the current volatility of the fuel oil market, for the purposes of EI's proposed modeling efforts, the Companies suggest the use of a fuel oil price forecast based on the *International Energy Outlook (IEO) 2005* report issued in July 2005 by the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy ("DOE"). Please refer to the attached detailed discussion entitled ***Fuel Forecast Considerations*** attached hereto as Exhibit E for the suggested, base, low and high case fuel price forecast for the Companies.

In addition, the Companies suggest that updated coal forecasts be used. The Companies will provide the Neighbor Island Coal Price Forecast and an updated HECO Coal Price Forecast shortly upon its completion.

<u>Background</u>

At one time, HECO examined a "basket" of outside forecasts that were readily available to the Companies and the public. Over the years, however, the source of readily available historical fuel price data and long-term forecasts that are useful in developing a meaningful long-range forecast of prices for the Companies fuel types have dwindled. Accordingly, the Companies forecasts have more recently focused on the historical information collected and price forecasts made publicly available by the EIA.

The EIA, created by Congress in 1977, is established as the single Federal Government authority for energy information. EIA's mission is to provide high quality, policy-independent energy information to meet the requirements of Government, industry, and the public in a manner that promotes sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. By law, EIA's products are prepared independently of Administration policy considerations. EIA neither formulates nor advocates any policy conclusions. Accordingly, EIA's data, forecasts and analysis are widely used by Federal and State agencies, industry, media, consumers and educators.

Few, if any, entities or individuals that analyze the energy market can dedicate resources comparable to that of EIA or match the depth and breadth of their integrated analysis. The EIA budget for fiscal year 2005 is $84 million, with a staff of 370 people, along with 250 support service contractors, who design and run their energy data and analysis system. EIA collects, analyzes and disseminates information on petroleum, natural gas, electricity, coal, nuclear, renewable fuels and alternative fuels.

EIA has two general projection periods for its forecasts on energy supply, demand and price projections for the U.S. and the world– the short term (next 6 to 8 quarters), and the mid-term (approx. next 20 years). The mid-term 20-yr. forecasts, updated annually, include the ***Annual Energy Outlook (AEO)***, the national forecast typically published in January, and the ***International Energy Outlook (IEO)***, the international forecast typically published in July.

By using the historical relationship between the EIA published crude prices and the petroleum fuels– low sulfur fuel oil ("LSFO"), medium sulfur fuel oil ("MSFO") and diesel - used by the Companies, a Fuel Oil Price Forecast has been developed for the long-range planning needs of the Companies. This approach utilizes the best publicly available information in a consistent method that is appropriate for the Companies' fuel oil requirements.

The fuel oil market is going through its most volatile condition since the Gulf War in 1990-1991. While the determination of key underlying assumptions, such as future fuel prices, used in the long range planning process is clearly easier during stable market conditions, the challenge of forecasting fuel prices during volatile market conditions make it ever more important to consistently apply a methodology that derives a fundamentally sound forecast.

Prudent planning, therefore, requires taking into account past experience, and available information on the "fundamentals" underlying the "behavior" of fuel prices. It is notable that older fuel price forecasts, following fuel price spikes, tended to over forecast fuel prices. Through the '80s and into the early '90s, world oil prices were forecast by EIA to cost several times higher than the prices actually turned out to be (see Figure 1). Likewise, HECO's LSFO forecast exhibited a similar over-forecasting versus actual prices (see Figure 2).

Figure 1

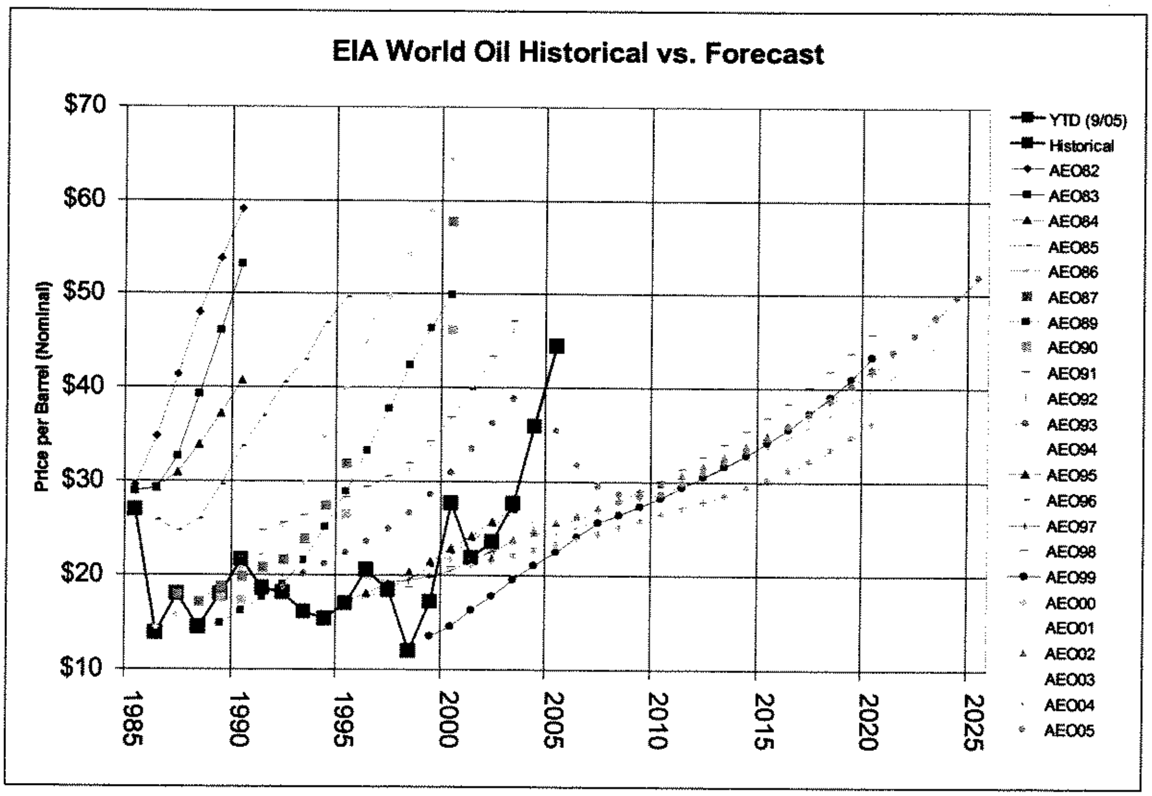
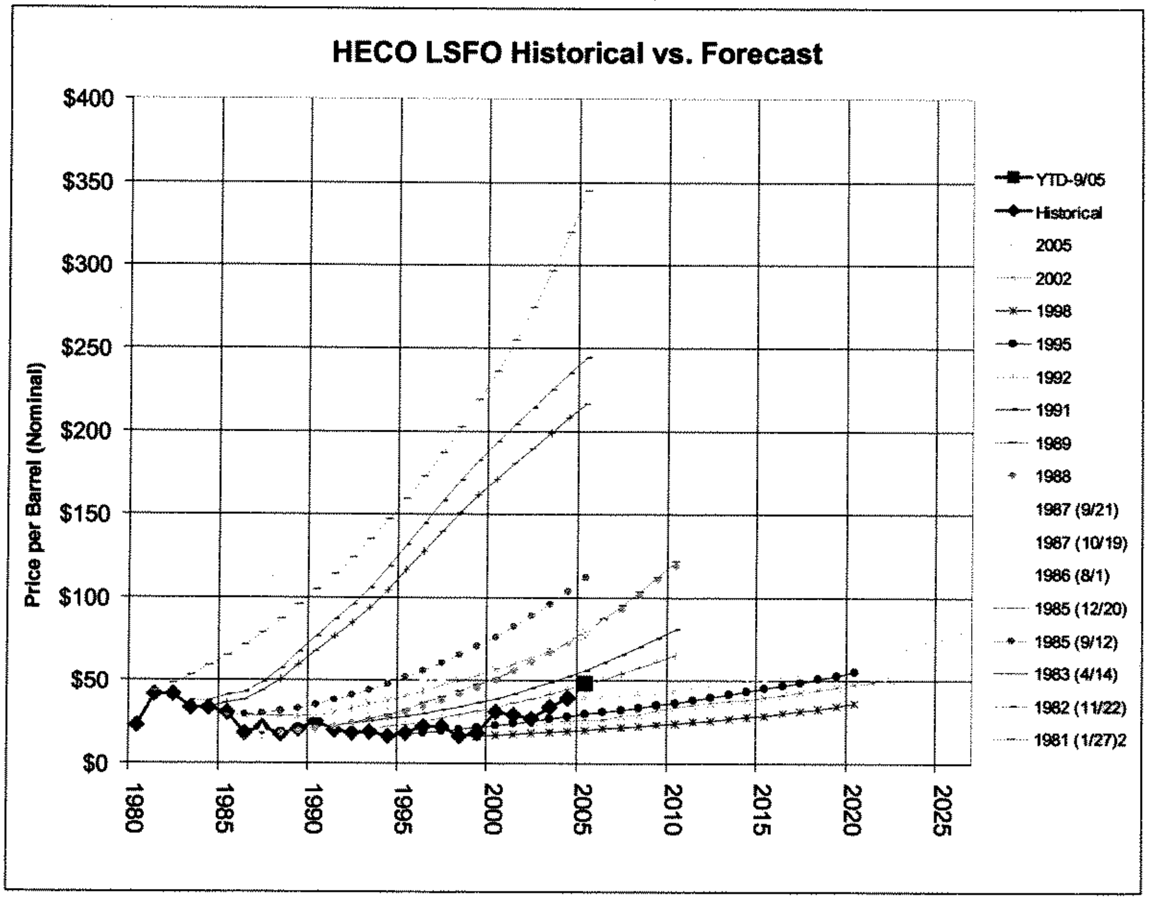


Figure 2



More recent long-term forecasts have underestimated fuel prices in the shorter-term, while the degree to which they may deviate from actual future prices over the long-term remains to be seen. Market fundamentals, however, suggest there are points at which marginal production costs for new supply or technologies will create long-term plateaus, rather than a continuous rise in oil prices. Higher oil prices will at some point drive lower demand with associated price increase suppression.

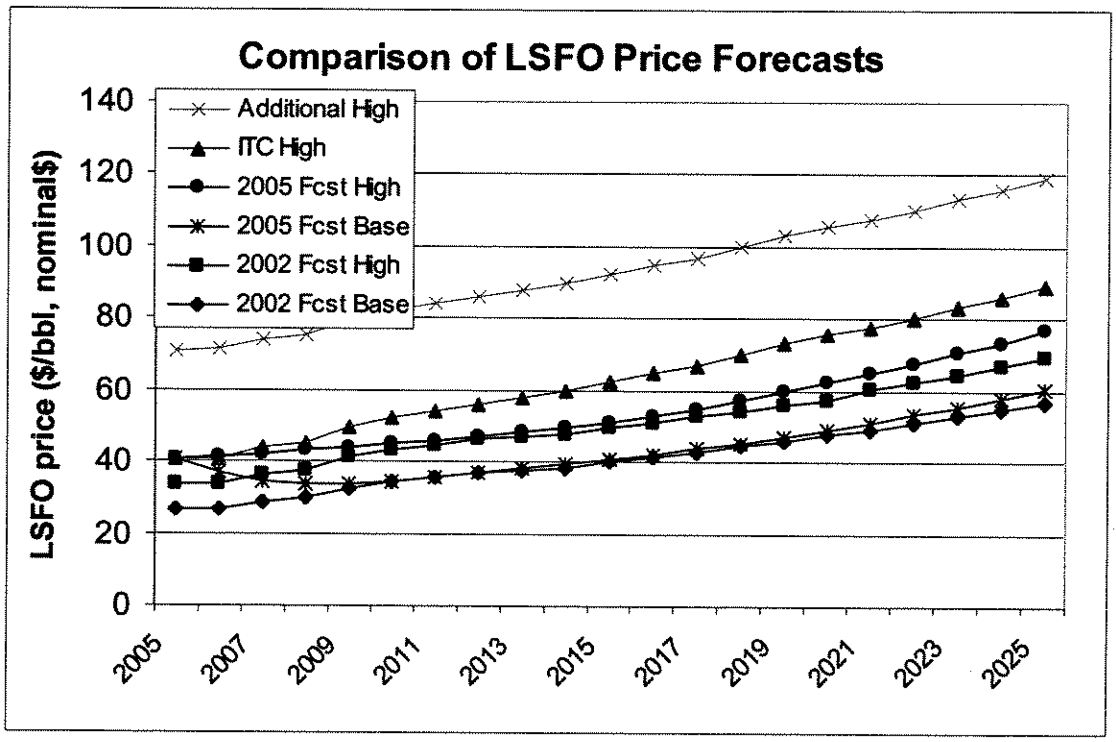
EIA recognizes that there are price constraints on ever-increasing fuel prices. In the

EIA's July 2005 *IEO* report, while noting that oil prices have been highly volatile over the past 25 years, and periods of price volatility can be expected in the future principally because of unforeseen political and economic circumstances, it is recognized that market forces can play a significant role in restoring balance over an extended period. High real prices deter consumption and encourage the emergence of significant competition from large marginal sources of oil, which currently are uneconomical to produce, and other energy supplies. Persistently low prices have the opposite effects.

EIA also considered that limits to long-term oil price escalation include substitution of other fuels for oil, marginal sources of conventional oil that become reserves (i.e., economically viable) when prices rise, and non-conventional sources of oil that become reserves at still higher prices. Advances in exploration and production technologies are likely to bring prices down when such additional oil resources become part of the reserve base. EIA further discussed the view that there remains significant untapped production potential worldwide, especially in deepwater areas. EIA's estimates of incremental production are based on current proved reserves and a country-by-country assessment of ultimately recoverable petroleum.

Geopolitical considerations, however, will lead to potentially more cycles. Given the cyclical experience with oil prices and likelihood of continued market volatility based on an analysis of sound fundamentals and market behavior as captured by the EIA, the Companies look to sensitivity scenarios that bracket the reasonably expected outcomes to meet the need of a 20-30 year planning period. In IRP-3, several sensitivity scenarios have been used. One high forecast sensitivity case was developed by the RIP technical Advisory Group. And given the most recent experience, an even higher sensitivity has been developed for the final RIP report submission, which exceeds the most recently experienced fuel prices (see Figure 3).

Figure 3



Recommendation

As stated above, for the purposes of EI's proposed modeling efforts, the Companies suggest the use of a fuel oil price forecast based on EIA's *International Energy Outlook (IEO) 2005* report. The *IEO 2005* report was issued in July 2005, whereas the *AEO 2005* report was issued in January 2005. The EIA used an additional six months of World Oil Price historical results to refine their *AEO 2005* forecast to reflect higher World Oil Prices.

The results of the *IEO 2005* based fuel oil price forecasts reflect higher fuel oil prices anticipated for all of the Companies major fuel oil types. These higher fuel oil prices are based upon fuel market fundamentals utilizing the latest publicly available information from EIA regarding the World Oil Price.

The EIA has indicated in its *IEO 2005* report issued in July that they anticipate that the *AEO 2006* report, to be issued in January 2006, may reflect even higher World Oil Prices than what was utilized in their *IEO 2005* report. The Companies will update their forecast once all necessary information (EIA's *AEO 2006* report and the Companies' fuel oil related data) is available. We anticipate its completion in February 2006.

Finally, the subject of using NYMEX future as a forecast of future oil prices was discussed during the workshops. The Companies have begun reviewing the proposed use of NYMEX's Crude Oil Futures Prices as a basis for a fuel oil price forecast model as raised by other participants in the RPS workshop. Some preliminary comments are included in the discussion entitled ***Fuel Forecast Considerations*** at Exhibit E. Of note, however, is that NYMEX warns all prospective traders that the Futures prices are not price predictions. This is important to consider when contemplating the appropriateness of this data as a major input to a fuel oil price forecast model. Similarly, John Conti, Energy Information Administration's Director of the Office of Integrated Analysis and Forecasting, in an informal discussion with HECO, stated that the futures market is not a good predictor of future prices. His comments parallel the NYMEX's cautionary statement on the use of a futures market as predictors of future oil prices.

D. Renewable Energy Resources

The impact that the assumptions for renewable resource selection and characterization will have on the results of the Commission's incentive regulation ("IR") investigation is highly dependent on the specific outputs of the planned simulations and how these outputs will be used to evaluate RPS and IR mechanisms. Although it is not clear to HECO what the specific outputs and evaluation methodology of the modeling will be, it is HECO's understanding that the intent of the EI model simulations is to assess IR mechanisms and not resource planning. As such, the accuracy of renewable energy costs is not as important as analyzing an appropriate range of costs to determine whether the IR mechanisms work over a reasonable range of renewable energy cost assumptions. (The Companies previously provided comments on renewable resources and costs on September 26, 2005 in its comments on Economists Incorporated's Second Concept Paper, "Proposals for Implementing Renewable Portfolio Standards in Hawaii", dated July 26, 2005.)

Economists Incorporated ("EI") states in their technical report that the selections or simulation results "... are not intended to replace or supersede the Integrated Resource Planning process on-going in the Commission.".[3] HECO agrees that resource planning should be conducted within the context of the utilities' Integrated Resource Planning ("IRP") process. In addition, HECO acknowledges that several sources of information will be used by EI to characterize renewable

[3] See Paragraph 105, Planned Computer Simulations Facilitating the Analysis of Proposals for Implementing the Renewable Portfolio Standards Provision in Hawaii, Economists Incorporated, September 23, 2005.

resources and the assessment of technical advances that will occur over the 30-year study period in renewable energy, and the impact these technical advances will have on costs, is challenging. However, the use of reasonable information to characterize the renewable resource options for the planned simulations will help facilitate meaningful analysis and conclusions.

HECO recommends that the most updated information be used to determine performance and cost estimates, including the use of IRP-3 data and/or cost ranges in EI model simulations. A table of specific renewable energy projects that are being considered and analyzed in IRP-3 is provided below to give an indication of reasonable individual project sizes.

Project/Technology	Size of Project, MW	Island(s)
Dedicated biomass (combustion)	25	Oahu; Big Island; Maui
Municipal solid waste (mass burn)	16	Oahu
	8	Big Island; Maui
Geothermal	25	Big Island
Wind	10-50	Oahu
	10-20	Big Island
	10	Maui
	0.25	Molokai; Lanai
Photovoltaics	0.1*	Oahu; Big Island; Maui
Run-of-river hydroelectric	14	Big Island
	6	Maui
Pumped storage hydroelectric	30	Big Island; Maui

* Blocks of 100 kW can be incorporated to form larger projects

In addition, realistic assumptions of available renewable resources and technologies, and associated costs, should be utilized in model simulations. Specifically, sound screening criteria and assessment of renewable resource and technology constraints must be used to place realistic upper bounds on the pool of available renewable resource options. Further discussion on technology screening criteria and resource and technology constraints is provided below.

Screening Criteria

Hawaii utilities, which operate isolated island-based grid systems, are unable to buy power from other states or utilities. Therefore, Hawaii utilities must use proven, commercial technologies to ensure reliable, cost-effective electricity for its customers. A sound set of screening criteria is needed to assess commercial status. For example, a set of five screening criteria is used in the HECO IRP-3 process to determine whether a technology is commercial (i.e., viable in the 0 to 5 year time frame):

(1) Multiple vendor availability– Multiple suppliers of equipment and systems, and system integrators to design and build with guarantees

(2) Proven technology– Technology is developed through research, development, demonstration, pilot and commercial stages, and developmental issues are identified and addressed through systematic assessment

(3) Utility scale– Ranges between several kilowatts to 180 megawatts based on accommodating load growth rates from 15 to 40 megawatts per year with three to four years between capacity additions

(4) Well-established capital and operation costs– Installation and operations costs are considered stable and readily available from several sources

(5) Resource availability– Adequate fuel supply, wind regime, solar insolation level, feedstock quantities, etc.

In-depth evaluation of technical aspects and market status using the above criteria determined that wind, photovoltaics, geothermal, biomass combustion, waste-to-energy combustion, hydroelectric, and pumped storage hydroelectric are currently at the commercial stage.

The criteria used in HECO IRP-3 to determine emerging technologies (i.e., viable in the 6 to 20 year time frame) include: (1) sole or multiple vendors, (2) emerging technologies, (3) potential for competitive capital and operating costs, and (4) resource availability. In-depth evaluation of technical aspects and market status using this set of criteria determined that ocean thermal, ocean wave, plasma arc gasification of municipal solid waste, fuel cells, and solar thermal electric (parabolic trough and parabolic dish) are currently emerging technologies.

Resource and Technology Constraints

The estimation and assessment of renewable resources for Hawaii over the 30-year study period must reflect both current and future resource availability and technology constraints. Although technology advances will occur, the pace and scope of these advances are difficult to ascertain. Consideration of certain resource and technology limitations will help ensure that proper perspectives on available renewable resource options are incorporated in model simulations. Some of these limitations, by resource, are discussed below.

Wind Energy

According to revised high resolution wind resource maps for Hawaii, rich wind regimes suitable for commercial wind farm development (e.g., NREL Class 3 or higher) on Oahu, Maui, and the Big Island is limited to a few areas on each island. The actual acreage that can support wind turbine installations, availability of these lands for wind farms, and community and environmental issues must be considered. For example, the recent decision by the Mayor to not support the plans for a potential wind farm at Kahe on Oahu eliminated one of the few sites deemed feasible for a wind farm. Development of the parcel targeted for the Kahe wind farm for other uses will permanently eliminate this site. The prospects for offshore wind development in Hawaii are low since wind resource maps revealed that the offshore wind speeds were too low in areas having shallow depths (50-100 foot depths are necessary for offshore wind development using today's technology) and that the depths were too deep in areas having high wind speeds.

Regarding wind technology, the trend towards larger wind turbines continues in an effort to improve the efficiency of energy capture and economies of scale. Whereas the average nameplate rating of turbines in the U.S. was 500 kW in 1996, current turbines for land applications are in the 1.5 to 2 MW size range. The 1.5 to 1.8 MW turbine nacelles have reached practical size and weight limits such that further increases will cause higher transportation, access road, and erection costs. Increases in tower heights (currently 65 to 80 meters) and blade lengths (current rotor diameters are up to 90 meters) will increase delivery and installation costs. Regardless of whether technology improvements are made to reduce weight and installation costs, logistical difficulties in siting large turbines, especially in remote areas, in Hawaii will remain. Technological advancements in offshore wind technology are also needed in order to tap Hawaii's offshore wind resource.

Biomass Energy

Limitations on agricultural resources in Hawaii must be considered. The availability of agricultural residues (e.g., wood wastes, sugarcane bagasse, etc.) is constrained by the limited wood products industry and declining agriculture industry in Hawaii (e.g., only two sugar factories are currently operating in Hawaii). The amount of suitable agricultural land that is available to support dedicated crops for biomass-to-energy conversion facilities is also limited in Hawaii. It is estimated that about 330 to 390 acres per MW is needed to support a dedicated biomass energy plant, depending on water availability for irrigation. In addition, the size and scale of dedicated biomass-to-energy plants is limited by the availability of fuel within a 50- to 75-mile radius due to the distance for economic fuel transportation. Most wood-fired plants have net capacities below 40 MW with most in the 10 to 30 MW size range.

The number and size of waste-to-energy facilities in Hawaii is constrained by the availability of the municipal waste resource net of recycling and non-combustible material and the growth limits of population and commercial waste streams. This must be considered when estimating potential power generation. The potential for power generation from landfill gas and biogas generated by sewage treatment plants is also limited by the resource. It is estimated that the size of specific landfill gas and sewage treatment biogas projects are on the order of a few megawatts each.

Geothermal Energy

Geothermal resources are known to exist only on the Big Island and possibly on Maui. Puna Geothermal Ventures, the operator of the existing 30 MW geothermal power plant on the Big Island, has stated its intention to eventually expand its capacity by 30 MW to a total of 60 MW. The timing of this expansion as well as the feasibility to expand the exploitation of the geothermal resource beyond this capacity is unknown. Cultural and community support issues may also constrain further geothermal development on the Big Island.

Solar Energy

The potential for commercial and residential photovoltaics is dependent on available rooftop space and land suitable to support photovoltaic installations (e.g., free of shading). A practical limit must be assumed for future installations.

Solar thermal technologies are emerging technologies that are in the early commercial, demonstration, and research and development stages. A 1992 study conducted by Dave Kearney & Associates states that the solar resource applicable to solar electric generating plants in Hawaii is approximately 25-30 percent lower than the Mojave Desert on an annual basis. Lower solar insolation resources would result in a commensurately higher cost of solar energy production since efficient operation of solar thermal electric systems, such as parabolic trough systems, require high direct normal insolation (i.e., the sunlight that is not scattered by the earth's atmosphere). The resource limitations and pace of future advances in solar thermal technology will dictate practical limits for its deployment.

Ocean Energy

Ocean energy technologies, such as ocean thermal energy conversion ("OTEC") and wave energy conversion, are in the research and development and demonstration stages. At present, there are no commercial OTEC facilities in operation. The siting of future on-shore and offshore OTEC systems in Hawaii may be constrained by the impact to the marine environment due to the large quantities of seawater required for operation. As an illustration, the amount of water discharged from a 100 MW closed-cycle OTEC would be equivalent to the nominal flow of the Colorado River into the Pacific Ocean.

Several wave energy technologies are currently being demonstrated. The availability of ocean area in Hawaii that is needed for commercial wave energy projects may limit deployment. Although area requirements will vary across technologies, it is estimated that a 90 MW project consisting of 180 Pelamis units (floating hydraulic-based conversion devices) would require about 6 square miles. Therefore, community support and permitting issues for these types of projects may dictate the future potential for wave energy deployment.

E. Federal Tax Incentives

The federal government offers two tax incentives applicable to renewable energy resources to offset federal income tax liability. The Renewable Energy Production Tax Credit ("REPTC") is available to owners of qualified facilities, including electric utilities. The Business Energy Tax Credit ("BETC"), however, is not available for public utility property. It is recommended that Economists Incorporated include federal tax incentives, along with state tax incentives for solar, wind, and photovoltaic in their financial modeling.

The REPTC provides an inflation-adjusted tax credit of 1.9 cents per kWh of electricity generated by systems that use wind, solar, closed-loop biomass (organic plant material planted exclusively for purposes of producing electricity), and geothermal resources. Systems that use open-loop biomass (agricultural livestock wastes, forest-related or solid wood waste materials, agricultural by-products or residues), small irrigation, qualified hydropower landfill gas, and municipal solid waste qualify for one-half of the credit or 0.95 cents per kWh. The tax credit can be claimed during a ten-year period beginning on the date the facility was placed in service (after August 8, 2005 through December 31, 2007), carried back one year, and carried forward twenty years. In addition, the REPTC is reduced by government grants, tax-exempt bonds, direct or indirect subsidized financing through government programs, or any other credit allowable with respect to the property. This reduction cannot, however, exceed 50% of the otherwise allowable credit.

The BETC provides a tax credit to businesses that invest or purchase eligible equipment in the United States. For eligible equipment installed from January 1, 2006 through December 31, 2007, a tax credit of 30% of expenditures for solar technologies (electricity generation or water heating), fuel cells, and solar hybrid lighting is available. Geothermal (not applicable to heat pumps) and microturbines are eligible for a 10% credit. The credit for fuel cells and microturbines are capped at $500 per 0.5 kW of capacity and $200 per kW of capacity, respectively. The BETC can be carried back one year and carried forward for twenty years.

F. Storage of Wind Energy

The impact of intermittent and non-dispatchable generation, such as wind energy, on the reliability and operations of the electric utility system is an important issue. High wind penetration in isolated island-based grid systems can impact both short-term (e.g., voltage and frequency fluctuations due to variable wind output caused by gusty winds) and long-term (e.g., curtailment of wind farms during low-demand periods) utility operations. The ability to store wind energy can help address the long-term issue– curtailment. Currently, wind penetration on the Big Island can approach 10% during low load demand periods (off-peak). Wind penetration is forecasted to increase on the Big Island due to the planned installations of a new wind farm at Hawi (HRD) and an expanded wind farm at South Point (Apollo).

Mitigation of adverse impacts on long-term utility operation can be achieved by storing wind energy when it is generated during off-peak periods and delivering this energy to customers when it is most needed during peak periods. This process would reduce the curtailment of wind farms and create a firm dispatchable resource. It must be noted, however, that energy storage facilities are considered peaking resources that provide energy for several hours (e.g., five hours during peak periods) and are unable, or not intended, to provide baseload electricity. Prudent utility planning will determine the type of generation needed (e.g., baseload versus peaking) to meet customer demands and maintain system reliability.

Commercial energy storage technologies that can provide multiple hours of generation include pumped storage hydroelectric ("PSH"), lead acid battery energy storage, and compressed air energy storage.[4] Although energy storage facilities could be located near wind farms, it is likely that such facilities would be located at strategic sites or locations with the necessary geological features (e.g., reservoirs with sufficient elevation change for PSH).

Pumped storage hydroelectric systems pump water from a lower elevation reservoir to a higher elevation reservoir using off-peak power, thus providing a load and reducing curtailment of wind farm output. During peak demand periods, the water is released from the higher reservoir to the lower reservoir to produce power in hydroelectric turbines. By doing so, PSH systems create firm dispatchable generation during peak periods and reduce curtailment of firm and intermittent renewable energy. In addition, PSH systems can provide synchronous (spinning) reserve, synchronous condenser operation, frequency and load regulation, and black start capability (ability to start operation when no electricity is available on line). Key considerations for PSH include cost, siting issues (requires adequate land area, suitable geological features, and water supply), round trip efficiency (AC to AC) as low as 70% due to the inclusion of pumping losses and inefficiencies, permitting, environmental issues, and community support.

The HECO utilities continue to assess PSH through its integrated resource planning ("IRP") process and various feasibility studies. Assessment studies of PSH systems on Oahu, Big Island, Maui, Molokai, and Lanai have been completed or are

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[4] Advanced batteries for utility-scale applications are currently under research, development and demonstration with some field demonstration experience. These include the sodium-sulfur (NaS) battery, polysulfide-bromide (Regenesys) flow battery, vanadium redox flow battery, zinc-bromine flow battery, and lithium ion battery. Flywheels and superconducting magnetic energy storage are considered short-term storage technologies.

ongoing.

Battery energy storage systems ("BESS") store off-peak or excess electricity in batteries and generate electricity during peak periods. Key considerations of BESS include cost, environmental and safety issues (due to the use of lead and sulfuric acid), round trip efficiency (AC to AC) ranging from 70-75% due to inefficiencies of battery and power conditioning equipment, and siting issues (requires large, well-ventilated area to house battery banks).

Compressed air energy storage ("CAES") systems compress air during off-peak periods, store the compressed air in large, natural geological features, and utilize the compressed air in combustion turbines to generate electricity during peak periods. Due to losses from pipe friction, air leakage, and compressor/expander inefficiencies, round trip efficiency of CAES systems are around 70%. A CAES system requires suitable geological features such as underground reservoirs with little or no pressure loss. Features suitable for CAES have not been identified in Hawaii.

G. <u>Capacity Value of Intermittent Resources</u>

The subject of capacity value for intermittent resources such as wind and PV was discussed during the workshops, since assigning capacity value to intermittent resources may improve their overall cost-effectiveness. Improving the cost-effectiveness of supply-side resources will then allow them to be proposed in hypothetical resource plans. HECO would like to reiterate some of the key points on this subject.

1. Capacity payments were debated at length during the Apollo Energy Corporation Docket No. 00-0135. In D&O No. 18568, dated May 30, 2001, the Commission stated that capacity payments for the Apollo (windfarm) were not warranted. The Commission found that HELCO would not be able to avoid or defer construction of firm generating units, and that Apollo was not under a continual obligation to supply power to HELCO upon demand.
2. HECO notes that under certain circumstances, intermittent resources my improve system reliability. On the other hand, intermittent resources generally do not allow the utility to defer or avoid firm capacity additions, and do not allow the utility to build less firm capacity. As-available energy suppliers do not have an obligation to deliver power in the amount needed and at the time needed.

Some workshop participants described the concept of Effective Load Carrying Capability (ELCC). A resource's ELCC value would be based on the probability of the as-available resource being available to serve load during the critical load periods. ELCC is a probabilistic measure of the "equivalent capacity" or "effective" amount of load carrying capability that is added to a generating system when one or more generating units is added. ELCC is determined through a probabilistic analysis of the relationship between a generating system's load and the Loss of Load Probability (LOLP).

LOLP is a probabilistic measure of the risk that the demand on a generating system will not be met due to random and sometimes multiple outages of generating units on the system. LOLP is dependent upon the number of available generating units within the generating system, the size and forced outage rates of each generating unit, and the demand on the generating system.

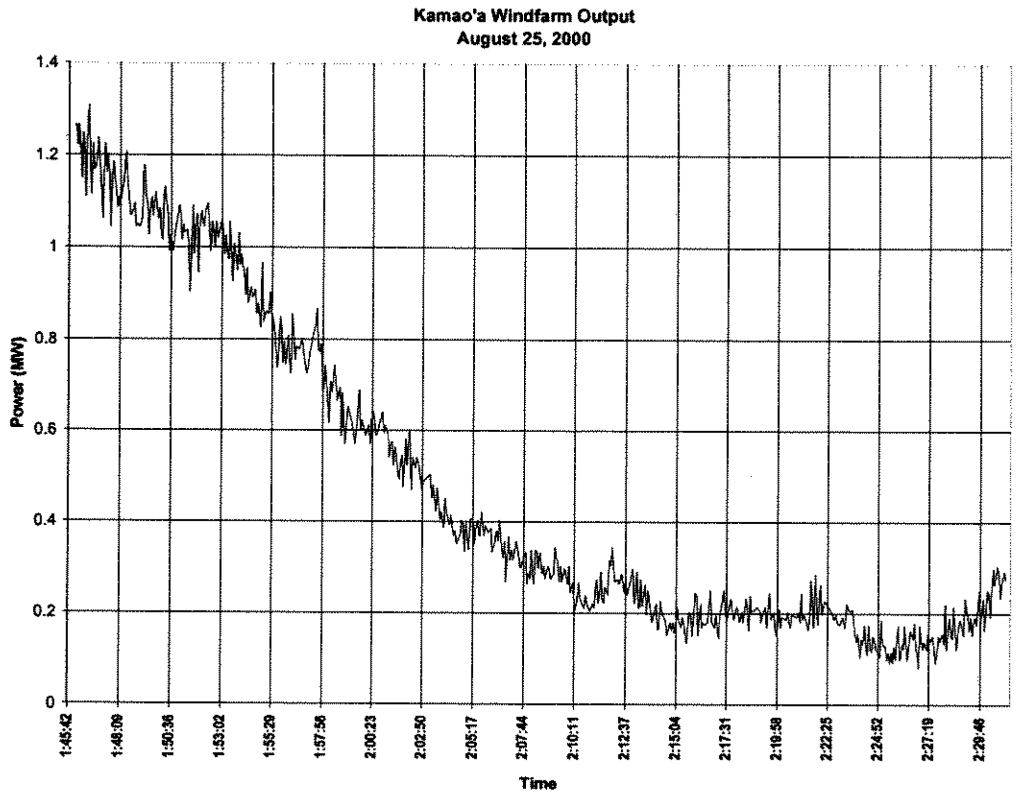
HECO acknowledges that the ELCC methodology will produce a non-zero ELCC number for intermittent as-available resources. However, an increase in reliability is not the same as having firm capacity. There are many significant differences between firm capacity and an increase in reliability (which can be equated to an ELCC for intermittent as-available resources).

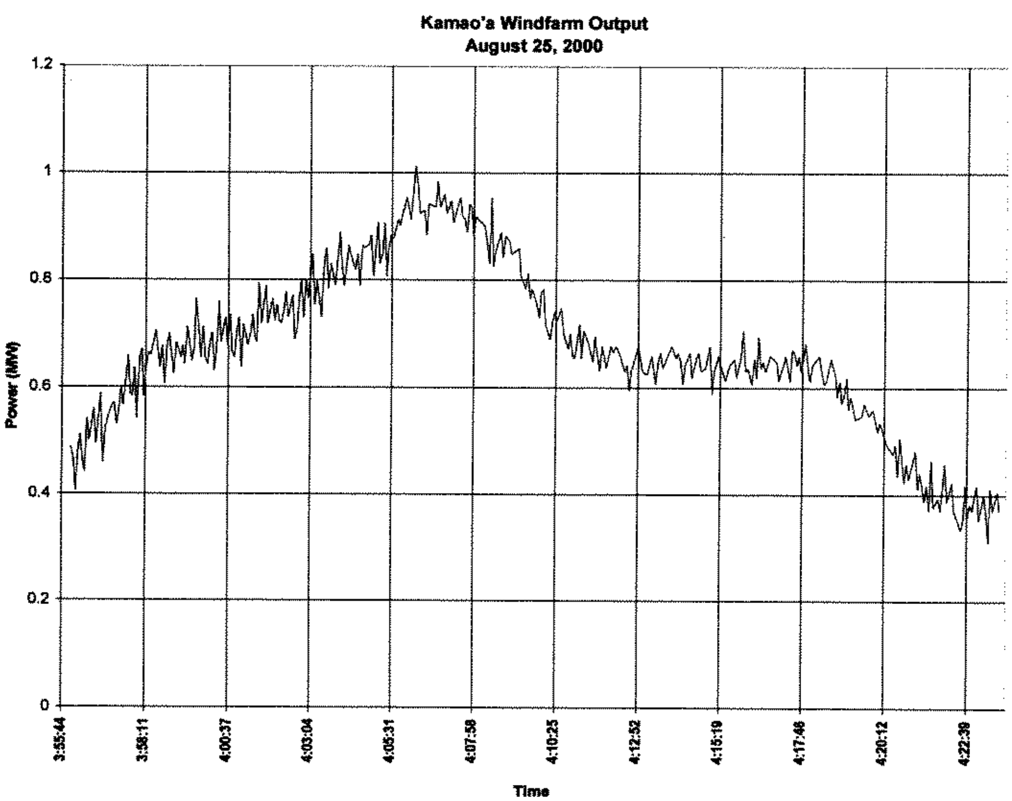
The HECO utilities cannot be expected to meet a portion of their obligation to provide firm power to customers based on receiving highly variable output from an intermittent resource. While the ELCC method may appear to produce an equivalent firm capacity, the fact is that the output from intermittent resources is highly variable and capacity cannot necessarily be provided by the as-available resource in the amount required and at the time required by the HECO utilities.

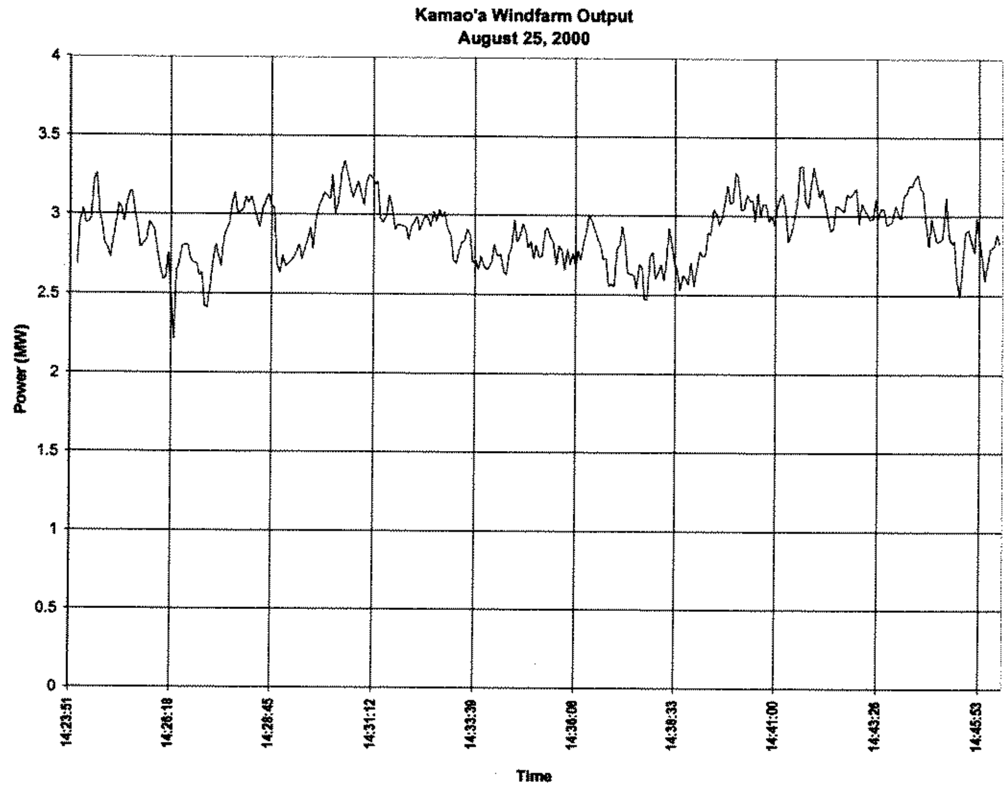
3. Modeling limitations can mask the true behavior of intermittent resources. For example, a mathematical probability may be translated into quantitative results that appear to be firm capacity. This approximation can obscure the fact that the power output from intermittent resources can vary from moment-to-moment, and cannot be dispatched. The modeler must be aware of these issues when developing hypothetical resource plans and interpreting simulation results.

For example, the random nature of intermittent resource generation is often approximated as transactions involving fixed blocks of energy. In aggregate, over a period of a month or year, the energy delivered by this approximation may be a reasonable representation of the average energy delivered by an intermittent resource. This representation may be adequate for specific uses, such as estimating an intermittent generator's contribution toward RPS in a given year (an energy-based calculation, over a relatively long period of time).

It is not suitable for capacity planning, however, since the actual behavior of intermittent resources is anything but constant. The following graphs illustrate the random and non-dispatchable nature of intermittent resource generation, even in the short-term. Submitted as HELCO-R-203 in Docket No. 00-0135, they illustrate the power output of the Kamao'a windfarm, measured every four seconds.


Kamao'a Windfarm Output
August 25, 2000
Power (MW)
Time
1.4
1.2
1
0.8
0.6
0.4
0.2
0
1:45:42
1:48:09
1:50:36
1:53:02
1:55:29
1:57:56
2:00:23
2:02:50
2:05:17
2:07:44
2:10:11
2:12:37
2:15:04
2:17:31
2:19:58
2:22:25
2:24:52
2:27:19
2:29:46


Kamao'a Windfarm Output
August 25, 2000
Power (MW)
Time
1.2
1
0.8
0.6
0.4
0.2
0
3:55:44
3:58:11
4:00:37
4:03:04
4:05:31
4:07:58
4:10:25
4:12:52
4:15:19
4:17:46
4:20:12
4:22:39



4. Power Purchase Agreements (PPA) with developers of intermittent resources generally do not include the contractual requirements that allow the utility to avoid capacity costs. These contractual requirements are typically included in firm capacity PPAs. For example, PPAs for intermittent resources generally:

   a. do not contain a long-term contractual commitment (say, 20 years);

   b. do not include a minimum availability requirement;

   c. do not include penalties for failure to deliver capacity;

   d. do not allow for late charges or liquidated damages to be assessed if the schedule milestones are missed, or if the facility is not operational by a certain date, or if the facility is not even built;

e. do not have a requirement for the project to maintain production levels;

f. do not have a requirement for the project to repair non-functioning equipment;

g. do not have a requirement for acceptance tests to determine the capacity of the resource, and does not allow for any adjustment to the firm capacity payment, if any; and

h. do not have specified scheduled overhaul periods such that the utility can coordinate its maintenance schedules.

5. Some workshop participants commented that mainland ISOs had assigned capacities to intermittent resources. However, it was also explained that HECO is an isolated utility with no energy market available to purchase short-term transactions. In time of need, HECO cannot rely on any other source for "back-up" power.

6. Some workshop participants commented that a portfolio of geographically-diverse intermittent projects would lessen the risk that intermittent resources would be simultaneously unavailable. HECO cautions that the relatively small Hawaiian Islands may not provide the type of diversity envisioned. For example, during the Apollo docket, HELCO was able to describe instances when the power output from multiple intermittent resources was simultaneously zero.

7. The use of energy storage systems may address some of the short-comings of intermittent resources. When feasible and cost-effective, they could be an option in resource plans.

H. <u>Generating Resource Plan Units</u>

The Companies have certain future generating units which must be included as a supply-side resource in any resource plan developed.

On Oahu, HECO currently has an urgent need for firm generating capacity. Efforts to install a simple cycle peaking unit at Campbell Industrial Park have been under way since early 2003. Although the capacity to be provided by the unit is needed now, the unit is not expected to be installed sooner than 2009, because of the long lead time for environmental review, permitting and approvals, equipment procurement, and construction.

On the Island of Hawaii, Keahole Unit ST-7 is scheduled for installation in 2009 or sooner. This project will incorporate two existing combustion turbines into a combined-cycle system. Permitting efforts are already underway.

On Maui, MECO is already procuring equipment for Maalaea Unit M18, which is scheduled for commercial operation in 2006. This project will incorporate two existing combustion turbines into a combined-cycle system.

I. Demand-Side Management Programs

HECO's DSM programs described in its IRP-3 were developed with public participation and input from an advisory group in the IRP process governed by the Commission's IRP Framework. The resulting portfolio of DSM Programs were determined to be cost-effective. The program design, issues of cost recovery and utility incentives, and statewide issues such as whether or not goals should be established will be further evaluated in the Energy Efficiency Docket (Docket No. 05-0069).

HECO recommends that its IRP-3 DSM Program proposals be adopted in total without changes for the purpose of the Act 95 RPS modeling. The Energy Efficiency Docket has already been established by the Commission for the purposes of examining the many issues associated with the DSM Programs and the instant effort being done on behalf of the Commission should not eclipse that docket. Instead, the levels of cost-effective DSM and the incentives for energy efficiency should be determined in the Energy Efficiency Docket.

J. System Integration Issues and Costs with Intermittent Renewable Energy

Intermittent renewable energy power plants, such as wind farms, have operating characteristics which result in system integration issues for electric grid operators. In general, these issues can be addressed through the design and operation of the wind farms, the other power generators connected to the grid, and other power electronic devices connected to the grid, and through changes in how the grid is operated. These additional measures are sometimes referred to as "ancillary services" associated with intermittent power and they have a measurable cost.[5]

In recent months, based in part on the experiences in Germany, Denmark, Spain and the western United States, the system integration issues associated with wind power have been evaluated and reported upon.[6,7,8] Of particular value is the work performed by California Energy Commission team in which 38 independent reports and studies were reviewed and 12 wind energy stakeholders were interviewed.[2]

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[5] Dr. R. Wiser remarked at the Act 95 workshop on 10/4/05 that the cost for ancillary services associated with wind power in the western United States could amount to $.05/kWh. Dr. K. Datta remarked at the Act 95 workshop on 10/4/05 that the cost to address system integration issues is a component of the overall cost of intermittent wind energy on an electric grid.

[6] Dyer, Jim et. al., Electric Power Group; Eto, Joe, Consortium for Electric Reliability Technology Solutions; Kondolleon, Don, California Energy Commission; *"Assessment of Reliability and Operational Issues for Integration of Renewable Generation,"* presented at the California Energy Commission Workshop, Sacramento, California, February 3, 2005.

[7] Red Electrica de Espana; *"Experience with Rapid Growth of Wind Generation in Spain,"* May 2004.

[8] Dr. H. Bouillon et. al.; *"Wind Report 2004,"* E.ON Netz Gmbh, Germany, 2004.

The major findings may be summarized as follows:

- The electric power production from a wind farm does not correlate with the system load and will increase the load following requirement of the regulating units connected to the grid.

- Wind power production is unpredictable and incompatible with the Automatic Generation Control (AGC) feature of a grid energy management system (EMS).

- For the E.ON Netz grid (Germany), the percentage contribution of wind power in covering the daily peak load varied from 0.1 to 32%.

- High levels of off-peak wind energy result in operating problems, and in some systems require off-peak energy production curtailments.

- Wind energy requires operating reserves equal to 50 to 60% of the installed wind power capacity. (Note, the HELCO system typically operates with an operating reserve of 4 to 5 megawatts. The HRD and Apollo wind energy projects will add 30 megawatts of installed wind power to the HELCO grid, and in accordance with this guideline will require the operating reserve to be increased by 15 to 18 megawatts.)

- Wind energy requires installed capacity equal to more than 80% of the installed wind energy capacity (on the large interconnected electric grids of Germany and Denmark).

- Wind farms must ride through short-duration frequency dips (e.g., 30 second dips to 57.8 Hz, or 3 minute dips to 58.5 Hz) to avoid cascading effects and consequential load shedding.

- Wind farms do not provide droop responses to frequency deviations, and thus, force other regulating units on the grid to work harder.

- Voltage/VAR control and low-voltage ride through are key contributors to grid reliability and must be incorporated in the design of wind farms.

- Wind farms are often connected to regions of the transmission system that do not have significant loads, and thus, the power must be transmitted across the system and may add to transmission system congestion.

These considerations are more important for island grids that are isolated and not interconnected to large, stiff grids like that which exist on the U.S. mainland and Europe. Moreover, as the amounts of wind energy increases the effects, risks, and costs become more pronounced, in part, because the wind energy is displacing power generators which have regulating capability.[9]

The consequence of these system integration issues include: (1) Wind farms having to incorporate more technical features, including power electronics; (2) Regulating units operating on the grid having to operate over wider load ranges with increased ramp rates; (3) Firm power units having to be dispatched at loads that are not cost effective; and (4) Operating and spinning reserve requirements are having to be increased by more than 50% of the installed capacity of the intermittent wind energy on the system. These factors result in increased ancillary costs for interconnecting intermittent wind energy to the grid.

[9] M. Macatangay remarked at the Act 95 workshop on 10/5/05 that generators that provide regulating capability for a grid would be regarded to have more value that those that do not.

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REGULATORY/ECONOMIC EXPERIENCE

Responsibility as a Public Utilities Commissioner of major New England state for setting rates and approving financings, rate designs and construction plans for electric, gas, telecommunications and water utilities.

Joint management of 100 member PUC Staff. Author, while Commissioner, of major decisions on extraordinary cancelled plant losses and utility holding company diversification.

Editor, while Policy Director of state Energy Office, of alternative energy resources handbook.

In private practice, author of manual on the licensing of energy and other major facilities and expert witness on principles of regulatory economics and purchased power incentives. Advice on technical qualifications of small power production facilities.

LEGAL EXPERIENCE

WIND –

In period since early 2001, (i) negotiation with Mitsubishi of EPC Contract (including Turbine Supply), Warranty Agreement and Maintenance and Service Agreement on behalf of windpower developer for two Texas projects (80 MWs and 240 MWs); (ii) negotiation with Nordex of Turbine Supply and Installation Agreement and Warranty Agreement on behalf of windpower developer; (iii) negotiation with Enron Wind of Turbine Supply and Installation Agreement (including Warranty) and Operation and Maintenance Agreement on behalf of windpower developer for NY 30 MW project; (iv) negotiation with Vestas of Warranty Agreement and with Mortenson of Balance of Plant EPC Contract on behalf of lender for 20 MW Minnesota project; (v) due diligence review of NEG Micon Turbine Supply and Installation Agreement, Turbine Warranty Agreement, and Turbine Operation and

Maintenance Agreement and of enXco Balance of Plant EPC Contract, BoP Warranty Agreement and BoP Operation and Maintenance Agreement on behalf of lenders for 30 MW Colorado project; (vi) due diligence review of Vestas Turbine Supply Agreement and Warranty and of enXco Balance of Plant, BoP Warranty and BoP Operations and Maintenance Agreements on behalf of lender for 6 MW Minnesota project; and (vii) due diligence review of related wind purchased power agreements.

PERMITS AND SITING –

Energy facilities siting approvals and environmental review of over 1,100 MWs of generation facilities in the period 1997 through the present (for Amercan National Power) and 160 MWs for Enron Power Enterprises, Inc. in period 1989 through 1993; siting approval of two transmission lines (in 1987 for Turners Falls Limited Partnership (Indeck Energy Services, Inc.) and in 1999 for ANP).

DG, DSM and OTHER RENEWABLES –

Due diligence review of powerplant project agreements (e.g. purchased power agreements and fuel supplies) and preparation of loan documentation for energy finance company providing debt financing to renewable energy, energy efficiency and cogeneration or distributed generation projects, including wind, landfill gas, district heating and cooling and large variety of standard Demand Side Management investments.

PPA's, PSA's, etc.

Drafting, negotiation and/or due diligence review of over 50 wholesale purchased power and bulk purchased savings agreements on behalf of both independent producers or suppliers (PPA's for Enron, Indeck, Coastal and smaller companies) (Purchased Savings Agreements for conservation suppliers such as EUA Cogenex) and on behalf of purchasing utilities (PPA negotiations for UNITIL Corp. and Eastern Utilities Associates; standard form PPA or PSA preparation for Duke Energy, Commonwealth Edison Company, Central and Southwest Power and Nevada Power Company). Expert testimony for Enron Power in Texas proceedings reviewing TXU PPA portfolio against industry standards.

Review and analysis of US and Canadian open access transmission tariffs for individual utilities and for regional transmission organizations; preparation of market-based pricing petition for affiliated power marketers.

Drafting and negotiations of energy savings or retail purchase agreements (including multi-fuel and multiple sites) with or for industrial hosts.

Negotiation of fuel purchase agreements for generation facilities and South American oil purchase negotiations.

Regulatory advice regarding utility purchased power and purchased savings procurements (RFP's), utility re-structuring and reorganization, municipal load aggregation and various aspects of retail and wholesale competition.

Drafting of energy-related legislation and of regulatory decisions regarding extraordinary losses and utility diversification.

MEDIA/PUBLIC RELATIONS EXPERIENCE

Speech and testimony writing for State Governor; TV and radio interviews on energy topics.

EMPLOYMENT

1987 -	Law practice specializing in energy and public utility matters
1983-1987	LeBoeuf, Lamb, Leiby & MacRae (Boston)
1981-1983	Commissioner, Massachusetts Department of Public Utilities (gubernatorial appointment)
1979-1981	Director, Policy and Evaluation, Executive Office of Energy Resources (Boston)
1975-1978	Mintz, Levin, Cohn, Ferris, Glovsky & Popeo (Boston)

EDUCATION

Harvard Law School, J.D., cum laude, 1975
Cornell University, M.S., Physics, 1973
Boston College, B.S., Physics; A.B., Mathematics, summa cum laude, 1970

PERSONAL

Married to former Boston Attorney, four children

EQUITY ADDER
INCENTIVE RATEMAKING

The utility could be incentivized to build its own renewable facility or enter into a renewable purchase power agreement with a bonus which is based on the equity component of a Similar Renewable Facility. The cost of such a Similar Renewable Facility could be determined in the IRP process, and it could be reviewed by the PUC in approving the IRP plan. If the bonus is based on the Similar Renewable Facility rather than the actual cost of the renewable facility, the utility would not have any incentive to build or acquire the facility at a higher cost. The estimate of equity associated with the Similar Renewable Facility would be the Equity Equivalent. For example, the bonus could be 100 or 200 basis points in excess of the normal return on equity applied by the Commission to the Company's rate base.

(A) Renewable Rate Base Plant

The plant capitalization would earn a return at the Company Cost of Capital, with a bonus which had been set in advance at the time the IR program was adopted. At the time the plant enters service and at each rate case thereafter, the bonus would be added to the cost of service and treated as any amount intended to reward equity. Normal, front-loaded cost of service recovery of plant costs would otherwise apply to the renewable rate base plant.

(B) Renewable Purchased Power Agreement (PPA)

When the Company enters into a renewable PPA, the Company would earn the bonus applied to the Equity Equivalent during each year of the PPA. The bonus would be added to the cost of service and treated as any amount intended to reward equity. At each rate case, the Equity Equivalent would be recalculated based on the Company's then expected costs for the remaining unexpired portion of the term of the PPA.

Daniel Violette's Educational Background and Professional Experience

Mr. Violette's full experience and educational background are provided in Docket No. 04-0113, HECO T-12 (pages 1 through 3) and HECO-1200. He has been working in the area of Demand-Side Management (DSM) since the late 1980's when he led a state-wide evaluation of energy efficiency programs in New Jersey encompassing all the DSM programs at both the investor-owned electric and gas utilities. This involved almost 100 DSM programs. He has continued work in the area of assessing the impact of DSM programs on energy use by performing work for over 30 utilities and covering over 1,000 programs. This work has included serving as the project manager for a number of state-wide evaluations through multi-year, multi-million dollar efforts in Michigan, Wisconsin, and New Jersey. He is the project manager for a state-wide evaluation of New York's energy efficiency programs funded through the Societal Benefits Charge (SBC) and implemented as part of that State's industry restructuring and move to retail choice. That project addresses over 30 energy efficiency and demand response programs across five utility service territories. In addition, he is the project manager for a state-wide impact evaluation of demand response programs being implemented by the three California investor-owned utilities. Evaluation work he has performed has frequently served as the basis for utilities filing for DSM incentives and lost margins in several states.

He has worked on policy issues surrounding DSM as a consultant to various state and utility DSM collaborative efforts in Massachusetts, California, Ohio, Kentucky, Utah, and Florida. He has testified in rate cases covering a wide variety of issues, including DSM incentives, and also addressed a range of rate case issues including cost allocation, tariff design, performance-based rates, and prudency issues.

He has presented a number of papers at meetings of the National Association of Regulatory Utility Commissioners (NARUC), led workshops for the U.S. Environmental Protection Agency and NARUC related to energy efficiency, authored reports for NARUC on principles for regulating DSM programs, and been an invited speaker and contributor to NARUC Conference proceedings. He has developed guidebooks related to energy efficiency for regulators (through Oak Ridge National Laboratory), for the International Energy Agency (IEA), and for the California Measurement Advisory Council (CALMAC). He is working on a guidebook for valuing demand response resources (DRR) and the integration of DRR in planning for the IEA with approximately 20 countries directly contributing funds to this IEA Annex and 15 separate U.S. entities also contributing, including state commissions, utilities, independent system operators, associations (e.g., the Association of Western States' Governors) and the U.S. Department of Energy.

His industry experiences include serving three elected terms as the President of the Association of Energy Services Professionals (AESP) and serving as the founding Vice Chair of the Peak Load Management Alliance (PLMA). He serves on the Boards and Executive Committees of both the AESP and PLMA.

Utility Comments on Strategist Databases

Please refer to the transmittal letter from HECO to the Hawaii Public Utilities Commission, "Act 95 Workshop – Data Request from HECO, HELCO and MECO", dated February 28, 2005. That letter describes (17) factors which should be taken into account during the simulation process, and in part summarizes the February 10, 2005 conference call with Economists Inc. In addition, HECO filed its "Comments Relating to the RPS Second Concept Paper" on September 26, 2005. Comments and questions that are specific to the calculation of Avoided Cost can be found on pages 8 thru 11 of Exhibit A. As a supplement to the February 28, 2005 transmittal letter and the September 26, 2005 comments letter, HECO is providing comments and questions based on Economists Incorporated technical paper, "Planned Computer Simulations Facilitating the Analysis of Proposals for Implementing the Renewable Portfolio Standards Provision in Hawaii", dated September 23, 2005, and the presentations and discussions from the Act 95 Workshops held on October 3 – 5, 2005 (both "Workshop II" and "Technical Workshop").

Utility Comments on Section II of the Technical Paper, Software, Simulations, and System Assumptions

Paragraph 16 describes the "Baseline Simulations" that are to be performed. During the Workshop II, it was explained that the Baseline Simulations would consist of modeling a recent historical year (i.e., 2004). Simulated results would then be compared against actual results, to verify proper operation of the model, and if necessary, to develop calibration mechanisms. It is not clear how these simulations will be performed because the databases that were given to the PUC did not include actual 2004 data. As indicated in HECO's letter dated February 28, 2005 that transmitted the Strategist databases, HECO reiterated in item 8 that the databases provided would not have "baseline year of 2004" data included. It would not be prudent engineering judgment to use only the most recent historical year of data as a forward looking assumption into the future. For long range planning, many of the operational costs and characteristics of the utility systems are based on multiple year historical averages, and these planning estimates may vary from the actuals of a recent year (like 2004). Calibration mechanisms may be appropriate, but it is unclear how the calibration simulations will be developed and used.

Paragraph 20 indicates that "All starting values in the model are to be calculated using a base year". The terminology "base year" should be clarified and how the base year concept relates to the model's desired objectives. The "base year" in Strategist identifies the year which is being used as the basis for all the input costs. For example, the capital cost for a Proview alternativesuch as wind is assumed to be in 2003 dollars if the base year in the Strategist database is 2003. However, simply changing the base year in Strategist (to 2004, say) will not accordingly change all the inputs and outputs to reflect the revised reference year dollars. All the inputs must be calculated or set to the base year dollars, then put into Strategist. As indicated in Appendix A of HECO's February 28, 2005 database transmittal, the HECO database uses a base year of 2003, HELCO database uses a base year of 1996, and MECO's Maui database uses a base year of 1997. Modifying the base year to 2004 will be a laborious process. For example, all the cost data must be adjusted outside of the model, to 2004 dollars, and then input back into Strategist. However, if the intent was to have the results out of Strategist to be in "present value" of 2004 dollars, then the base year of the database does not necessarily have to be changed. Having all output costs in 2004 dollars can be done by revising the discount rate input in the databases without needing to change the base year and all other inputs of the database.

Paragraph 21 states that "A study period of 30 years is to be used in the planned simulations." Strategist defines the term "study period" as the "planning period" plus "end-effects", so HECO would like to get clarification on the desired objective. Is the intent to use a 30 year "planning period" for the simulations, or is the "study period" actually 30 years, with some subset defined to be the "planning period"?

Utility Comments to Section III, Specific Assumptions for Each Utility

A. HECO

As described in the February 28, 2005 transmittal letter (see Page 1 of Attachment A to the letter), seven Strategist databases were provided, representing the Finalist Plans developed during HECO's IRP-3 process. Finalist Plan 6, the Combination Plan ("IRP3F6.fsv"), is the appropriate database for Act 95 analysis. HECO expects to file its IRP-3 with the Commission by the end of October, 2005, and the Preferred Plan therein is based on the Combination Plan.

Paragraph 29 refers to Appendix A for specific assumptions for the HECO database. The table in Appendix A should clarify the fixed and variable O&M costs. The Table in Appendix A appears to represent the fixed and variable O&M costs as constant amounts, while these amounts are not constant when the model is run. The data (e.g., fixed and variable O&M costs) is shown in the database input as constant but the escalation rates are applied to the values when the model is run. The escalation rate is based on the GDPIPD and is included in the database that was provided.

Paragraph 32 states that "For HECO, the minimum reserve margin is assumed to be 0%, and the maximum reserve margin, 50%". Based on the description in the technical paper, and the discussion at the Workshop II, it appears that the model will be using the minimum reserve margin as a proxy mechanism for triggering capacity additions. As we indicated in our February 28, 2005 transmittal letter item 4, and as was mentioned at the Technical Workshop on October 5, 2005, the HECO utilities have customized subroutines which model our specific capacity planning and operating criteria. It is not known if Economists Inc. received these proprietary subroutines for their use. Economists Inc. indicated that they would also use the maximum loss of load hours ("LOLH"), in Strategist for capacity additions in the HECO system. The HECO specific reliability guideline uses loss of load probability ("LOLP"), which is not exactly equivalent to LOLH. This was described in our February 28, 2005 transmittal letter item 6.

Paragraph 33 mentions the fuel cost assumptions that were included in the database that was provided. These costs were based on the utility's 2002 fuel price forecast and should be updated. Please refer to the discussion on the section concerning the fuel forecast.

Paragraph 34 must be clarified because the fixed and variable costs are escalated and not constant. See our comment to paragraph 29 and Appendix A.

B. HELCO

Paragraph 35 refers to Appendix B for specific assumptions for the HELCO database. As discussed in the following paragraph, the table in Appendix B should correct the peak annual load growth. In addition, the Table in Appendix B should clarify the fixed and variable O&M costs. The Table in Appendix B appears to represent the fixed and variable O&M costs as constant amounts, while these amounts are not constant when the model is run. The data (e.g., fixed and variable O&M costs) is shown in the database input as constant but the escalation rates are applied to the values when the model is run. The escalation rate is based on the GDPIPD and is included in the database that was provided.

Paragraph 36 refers to incorrect load growth assumptions for HELCO. Range for the peak growth is shown incorrectly and should be 2.16% to 2.96% based on the database that was provided in our February 28, 2005 transmittal.

Paragraph 38 states that "For HELCO, the minimum reserve margin is assumed to be 20%, and the maximum reserve margin, 100%". As indicated in our February 28, 2005 transmittal letter item 4, and as was mentioned at the Technical Workshop on October 5, 2005, the HECO utilities have customized subroutines which model our specific capacity planning and operating criteria. It is not known if Economists Inc. has received these proprietary subroutines for their use. For HELCO, a minimum reserve margin of 20% is also used in Strategist.

Paragraph 39 indicates that "Annual hydro energy generation and hydro energy seasonal distribution in HELCO are assumed to be constant". This is correct only from 2006 and on and should be clarified. The Puueo Hydro assumption changes in 2005 because a rehabilitation project for this unit is being completed and was included in the database given to the PUC in HECO's February 28, 2005 transmittal.

Paragraph 40 states that "From 2005 onwards, transaction energy existing before any power plant additions in HELCO is assumed to remain 2003 levels". This statement should be clarified because there are assumptions that would need to be incorporated that would occur after 2003. For example, the repowered Apollo wind project was not included in the database that was provided in the February 28, 2005 transmittal because the PPA was not signed and approved yet. For the IRP-3, the repowered Apollo is assumed to be installed in December 2006 which would replace the existing Apollo wind farm. Also, HCPC was terminated at the end of 2004 and this data was already included in the database that was transmitted.

Paragraph 41 states that "Seasonal distribution of transactions existing before any power plant additions in HELCO are assumed to be constant throughout the year". This statement needs to be clarified because many transactions, such as wind and hydro, are seasonal in nature and should have seasonal distribution that changes throughout a year. It is not apparent as to whether the intent was to keep the seasonal distribution of the transactions of a given year constant for all years following, or if the intent was something else.

Paragraph 42 mentions the fuel cost assumptions that were included in the database that was provided. These costs were based on the utility's 2002 fuel price forecast and should be updated. Please refer to the discussion in the section concerning the fuel forecast.

Paragraph 43 should be clarified because the costs are escalated and not constant. See our comment to paragraph 35 and Appendix B. Also, the costs in the database were based on Unit Information Forms from IRP-2. These costs, as well as all other future units that could be analyzed for installation, have been updated as part of IRP-3.

Paragraph 44 should be clarified because the fixed and variable costs are escalated and not constant. See our comment to paragraph 35 and Appendix B.

C. MECO

Paragraph 45 refers to Appendix C for specific assumptions for the MECO databases covering Maui, Molokai, and Lanai. The tables in Appendix C should correct the peak annual load growth and clarify the fixed and variable O&M costs. The Table in Appendix C appears to represent the fixed and variable O&M as constant amounts, while these amounts are not constant when the model is run. The data (e.g., fixed and variable O&M costs) is shown in the database input as constant but the escalation rates are applied to the values when the model is run. The escalation rate is based on the GDPIPD and is included in the database that was provided.

Maui

Paragraph 46 refers to incorrect load growth assumptions for MECO. Range for the peak growth is shown incorrectly and should be 2.37% to 4.21% based on the database that was provided in our February 28, 2005 transmittal.

Paragraph 48 states that "For MECO, the minimum reserve margin is assumed to be 0%, and the maximum reserve margin, 100%". As indicated in HECO's February 28, 2005 transmittal letter item 4, and as was mentioned at the Technical Workshop on October 5, 2005, the HECO utilities have customized subroutines which model our specific capacity planning and operating criteria. It is not known whether Economists Inc. has received these proprietary subroutines for their use. For MECO, similar to HELCO, a minimum reserve margin of 20% is also used in Strategist.

Paragraph 49 states that "From 2005 onwards, transaction energy existing before any power plant additions in Maui is assumed to remain 2003 levels". This statement should be clarified because there are assumptions that would need to be incorporated that would occur after 2003. For example, the Kaheawa wind project was not included in the database that was provided in the February 28, 2005 transmittal because the PPA was not signed and approved yet. The Kaheawa wind project is assumed to be placed in service in June 2006.

Paragraph 50 states that "Seasonal distribution of transactions existing before any power plant additions in Maui are assumed to be constant throughout the year". This statement should be clarified because many transactions, such as wind and hydro, are seasonal in nature and should have seasonal distribution that changes throughout a year. It is not apparent as to whether the intent was to keep the seasonal distribution of the transactions of a given year constant for all years following, or if the intent was something else.

Paragraph 51 mentions the fuel cost assumptions that were included in the database that was provided. These costs were based on the utility's 2002 fuel price forecast and should be updated. Please refer to the discussion in the section dealing with the fuel forecast.

Paragraph 52 should be clarified because the fixed and variable costs are escalated and not constant. See our comment to paragraph 45 and Appendix C.

Molokai

Paragraph 53 refers to incorrect load growth assumptions Molokai. Range for the peak growth is shown incorrectly and should be 0.71% to 2.28% based on the database that was provided in our February 28, 2005 transmittal.

Paragraph 54 states that "The seasonal load shape in Molokai is assumed to be a weighted average of that in HECO, HELCO, and Maui". It is not appropriate to assume a weighted average of HECO, HELCO, and Maui for the island of Molokai which has a very different load shape compared to the much larger islands. The load shape should be based on the 2004 hourly load data for Molokai which can be provided if deemed necessary.

Paragraph 55 states that "For Molokai, the minimum and maximum reserve margins are assumed to be a weighted average of those for HECO, HELCO, and Maui". For Molokai, using a reserve margin value that is a weighted average of the HECO, HELCO, and Maui systems would be inappropriate. The Molokai system is less than 5 percent the size of the Maui and HELCO systems, and less than 1 percent of the HECO system size. Therefore, using reserve margin criteria reasonable for those larger systems should not be used for the much smaller Molokai system. Instead, the Molokai Capacity Planning Criteria (attached) should be used.

Paragraph 57 is a repeat of paragraph 56.

Paragraph 58 mentions the fuel cost assumptions that were included in the database that was provided. These costs were based on the utility's 2002 fuel price forecast and should be updated. Please refer to the discussion in the section concerning the fuel forecast.

Paragraph 59 states "Unit fixed costs and variable costs of thermal units in Molokai are assumed to be a weighted average of those for HECO, HELCO, and Maui". The weighted average of costs should be based on similar-type diesel units from the Maui system, such as Maalaea Units M-1, M-2, M-3, X-1, and X2..

Lanai

Paragraph 60 refers to incorrect load growth assumptions for Lanai. Range for the peak growth is shown incorrectly and should be 0.96% to 1.93% based on the database that was provided in our February 28, 2005 transmittal.

Paragraph 61 states that "The seasonal load shape in Lanai is assumed to be a weighted average of that in HECO, HELCO, and Maui". It is not appropriate to assume a weighted average of HECO, HELCO, and Maui for the island of Molokai which has a very different load shape compared to the much larger islands. The load shape should be based on the 2004 hourly load data for Lanai which can be provided if deemed necessary.

Paragraph 62 states that "For Lanai, the minimum and maximum reserve margins are assumed to be a weighted average of those for HECO, HELCO, and Maui". For Lanai, using the reserve margin value that is a weighted average of the HECO, HELCO, and Maui systems would be inappropriate. The Lanai system is less than 5 percent the size of the Maui and HELCO systems, and less than 1 percent of the HECO system size. Therefore, using reserve margin criteria reasonable for those larger systems should not be used for the much smaller Lanai system. Instead, the Lanai Capacity Planning Criteria (attached) should be used.

Paragraph 63 mentions the fuel cost assumptions that were included in the database that was provided. These costs were based on the utility's 2002 fuel price forecast and should be updated.

Paragraph 64 is a repeat of paragraph 63.

Paragraph 66 states "Unit fixed costs and variable costs of thermal units in Lanai are assumed to be a weighted average of those for HECO, HELCO, and Maui". The weighted average of costs should be based on similar-type diesel units from the Maui system, such as Maalaea Units M-1, M-2, M-3, X-1, and X2.

<u>Utility Comments to Section IV, Regulation and the Hawaii RPS Provision</u>

B. Cost-of-service Regulation

Paragraph 92 explains "The three steps in modeling utility rates under cost-of-service regulation are functionalization, classification, and allocation, all of which are performed in order to assign costs to various rate classes." The first sub-bullet describes functionalization and assumes that we assign cost items to categories, such as production, transmission, and distribution in Strategist. The databases provided in the February 28, 2005 transmittal do not include transmission and distribution costs.

Paragraph 94 describes the three production modules in Strategist - - the Load Forecast Adjustment ("LFA") module, Generation and Fuel ("GAF") module, and Proview. The databases that were provided in the February 28, 2005 transmittal included Combined Heat and Power (CHP) forecasts as load modifiers in the LFA module. Footnote 30, page 19, regarding LOLP calculations should be clarified because Strategist only calculates loss of load hours which is not exactly equivalent to loss of load probability. It is not clear to HECO how the information from GAF runs will be used. There also needs to be clarification that Proview will not determine the "optimal scale, location, timing, and technology of capacity additions". The resource or technology needs to be input to Strategist as a given size. Further, it is not clear how location-specific information -- such as transmission costs – will be incorporated in the analysis.

Paragraph 95 explains that "In Strategist, the three financial modules that are central to the purpose at hand are the Capital Expenditure and Recovery ("CER") module, Financial Reporting and Analysis ("FIR") module, and the Class Revenue Module ("CRM")." As explained in item 3 of the February 28, 2005 transmittal, the HECO companies do not use these modules. Therefore HECO has no way of knowing what is used for modeling purposes. Financial information was provided in the February 28, 2005 transmittal and all the necessary data will have to be inputted into Strategist. The HECO utilities should be provided with the data that will be used and how it was incorporated into Strategist.

As we indicated in item 5 of our February 28, 2005 letter, many PPA calculations are done outside of Strategist due to their complexity. This information should be accounted for properly.

Utility Comments to Section V, Renewable Energy Resources in Hawaii

C. Representation of Candidate Renewable Resources

Paragraph 109 describes that "Remote or off-grid technologies, such as commercial and residential PV and sea water air conditioning, may be represented as DSM or conservation programs, in view of their effect of reducing load approximately by the amount of energy available from them, and their inability, by their nature as off-grid resources, directly to serve load elsewhere on the grid." In HECO's IRP-3 the PV resources are modeled as transactions. The HECO companies model the CHP forecasts as a load modifier in the LFA module.

Utility Comments to Appendix B were described above

Utility Comments to Appendix C were described above

Maui Electric Company, Ltd. • 210 West Kamehameha Avenue • PO Box 398 • Kahului, Maui, HI 96733-6898 • (808) 871-8461

March 15, 2005

Edward L. Reinhardt
President

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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Maui Electric Company, Limited

In accordance with paragraph 5.3a of General Order No. 7, MECO's Adequacy of Supply ("AOS") Report is due within 30 days after the end of the year. On January 31, 2005, MECO requested an extension of time, to no later than March 15, 2005, to file the AOS Report. The extension of time was needed to allow MECO to incorporate updates to its Combined Heat and Power ("CHP") projections. On February 9, 2005, the Commission issued Order No. 05-ORD-05, approving MECO's request.

MECO respectively submits the following information pursuant to paragraph 5.3a. of General Order No. 7.

Maui's 2004 system peak occurred on November 8, 2004 and was 206,500 kW (net) or 210,900 kW (gross). Lanai's 2004 system peak occurred on December 28, 2004 and was 4,900 kW (gross). Molokai's 2004 system peak occurred on January 12, 2004 and was 6,800 kW (gross). The total system capability of Maui had a reserve margin of approximately 19% over the 2004 system peak. Lanai had a 2004 reserve margin of approximately 112%. Molokai had a 2004 reserve margin of approximately 77%.

Attachment 1 shows the expected reserve margins over the next three years, based on MECO's 2004-2009 Sales and Peak Forecast dated June 25, 2004, and includes DSM impacts from the implementation of Maui Division's load management DSM programs forecasted to start in 2007.

MECO Combined Heat and Power Program

On October 10, 2003, MECO (along with HECO and HELCO, collectively, the "Companies") filed a PUC Application for approval of a proposed utility-owned Combined Heat

The following criterion is used to determine the timing of an additional generating unit for the Lanai Division and the Molokai Division:

New generation will be added to prevent the violation of any one of the rules listed below where "units" mean all units and firm capacity suppliers physically connected to the system, and "available unit" means an operable unit not on scheduled maintenance.

1. *The sum of the normal top load ratings of all units must be equal to or greater than the system peak load to be supplied.*

2. *With no unit on maintenance, the sum of the reserve ratings of all units minus the reserve rating of the largest available unit must be equal to or greater than the system peak to be supplied.*

3. *With a unit on maintenance:*

   a) *The sum of the reserve ratings of all units minus the reserve rating of the largest available unit must be equal to or greater than the daytime peak load to be supplied.*

   b) *The sum of the reserve ratings of all units must be equal to or greater than the evening peak load to be supplied.*

Potential Load Service Capability Shortfalls on Maui in 2005 and 2006

On Maui, in 2005 and in 2006, prior to the installation of M18, a nominal 17,100 kW (net) steam turbine generator, the Maui system could potentially experience load service capability (LSC) margin shortfalls, as shown in Attachment 2, unless the mitigation measures identified below are taken. Reserve margin is the difference between system generating capability and peak demand. The term "load service capability" is a measure of MECO's ability to meet system load requirements accounting for both planned maintenance and the loss of its largest unit. LSC margin shortfalls (which are indicated by values less than zero) are used as a planning tool to identify potential conditions of generating reserve capacity shortfalls and do not equate to either service interruptions or rolling blackouts. During periods when LSC margin values are less than zero, there is a possibility that a service interruption could occur if the largest unit is lost from service during the peak period.

In 2005, without mitigation measures, LSC margin shortfalls could occur in May, August, and October. In May, a LSC margin shortfall could occur during the periods when one-half of the dual train combined cycle (approximately 28 MW) is taken out of service for planned maintenance. The potential LSC margin shortfall in May is -4.1 MW. In August and October, LSC margin shortfalls could occur during periods of planned maintenance on M5 and K2 (approximately 11

Fuel Forecast Considerations

While the specific mechanics of developing a long-term fuel price forecast for the Hawaiian Electric Company ("HECO") and its utility subsidiaries, Maui Electric Company ("MECO") and Hawaii Electric Light Company ("HELCO") (collectively the "Companies") has varied to some degree over the years, the goal of the forecast has remained constant. And that goal is to develop an *objective* forecast based on sound analysis of market fundamentals as viewed by energy experts.

At one time, HECO examined a "basket" of outside forecasts that were readily available to the Companies and the public. Over the years, however, the source of readily available historical fuel price data and long-term forecasts that are useful in developing a meaningful long-range forecast of prices for the Companies fuel types have dwindled. Accordingly, the Companies forecasts have more recently focused on the historical information collected and price forecasts made publicly available by the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy (DOE).

The EIA and their Mission

The EIA, created by Congress in 1977, is established as the single Federal Government authority for energy information. Congress gave EIA independence from the rest of the DOE with respect to data collection, and from the whole Federal Government with respect to the content of EIA reports.

EIA's mission is to provide high quality, policy-independent energy information to meet the requirements of Government, industry, and the public in a manner that promotes sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. By law, EIA's products are prepared independently of Administration policy considerations. EIA neither formulates nor advocates any policy conclusions. Accordingly, EIA's data, forecasts and analysis are widely used by Federal and State agencies, industry, media, consumers and educators.

Few, if any, entities or individuals that analyze the energy market can dedicate resources comparable to that of EIA or match the depth and breadth of their integrated analysis.[1]

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[1]EIA analyzes the energy market through the following divisions:

a) Office of Information Technology
b) National Energy Information Center
c) Office of Resource Management
d) Statistics and Methods Group
e) Office of Oil and Gas
   i) Natural Gas Division
   ii) Collection and Dissemination Division
   iii) Petroleum Division

The EIA budget for fiscal year 2005 is $84 million, with a staff of 370 people, along with 250 support service contractors, who design and run their energy data and analysis system. EIA collects, analyzes and disseminates information on petroleum, natural gas, electricity, coal, nuclear, renewable fuels and alternative fuels. The EIA's energy data and analysis is fundamentals based, focusing on supply, demand, prices, forecasts, related economic and environmental issues, and finance. EIA issues a wide range of weekly, monthly and annual reports on energy production, stocks, demand, imports, exports, and prices, and prepares analyses and special reports on topics of current interest.

EIA has two general projection periods for its forecasts on energy supply, demand and price projections for the U.S. and the world – the short term (next 6 to 8 quarters), and the mid-term (approx. next 20 years).

- Mid-term 20-yr. forecasts (national and international) are updated annually.
    i. ***Annual Energy Outlook (AEO)*** is the national forecast and is typically published in January.
    ii. ***International Energy Outlook (IEO)*** is the international forecast and is typically published in July.
    iii. EIA forecasts employs the National Energy Modeling System (NEMS) computer programs designed to approximate the interactions of energy markets and provide insights into future changes in supply, demand, economic conditions, etc.
- Short-term forecasts are updated and made available on the internet monthly, and published quarterly in a hard-copy report titled ***Short-term Energy Outlook (STEO).***

By using the historical relationship between the EIA published crude prices and the petroleum fuels – low sulfur fuel oil ("LSFO"), medium sulfur fuel oil ("MSFO") and diesel - used by the Companies, a Fuel Oil Price Forecast has been developed for the long-range planning needs of the Companies. This approach utilizes the best publicly

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iv) Reserves and Production Division

f) Office of Coal, Nuclear, Electric and Alternative Fuels
    i) Electric Power Division
    ii) Coal, Nuclear and Renewable Fuels Division
    iii) Systems Support Division

g) Office of Energy Markets and End Use
    i) Energy Consumption Division
    ii) Energy Markets and Contingency Information Division
    iii) Integrated Energy Statistics Division

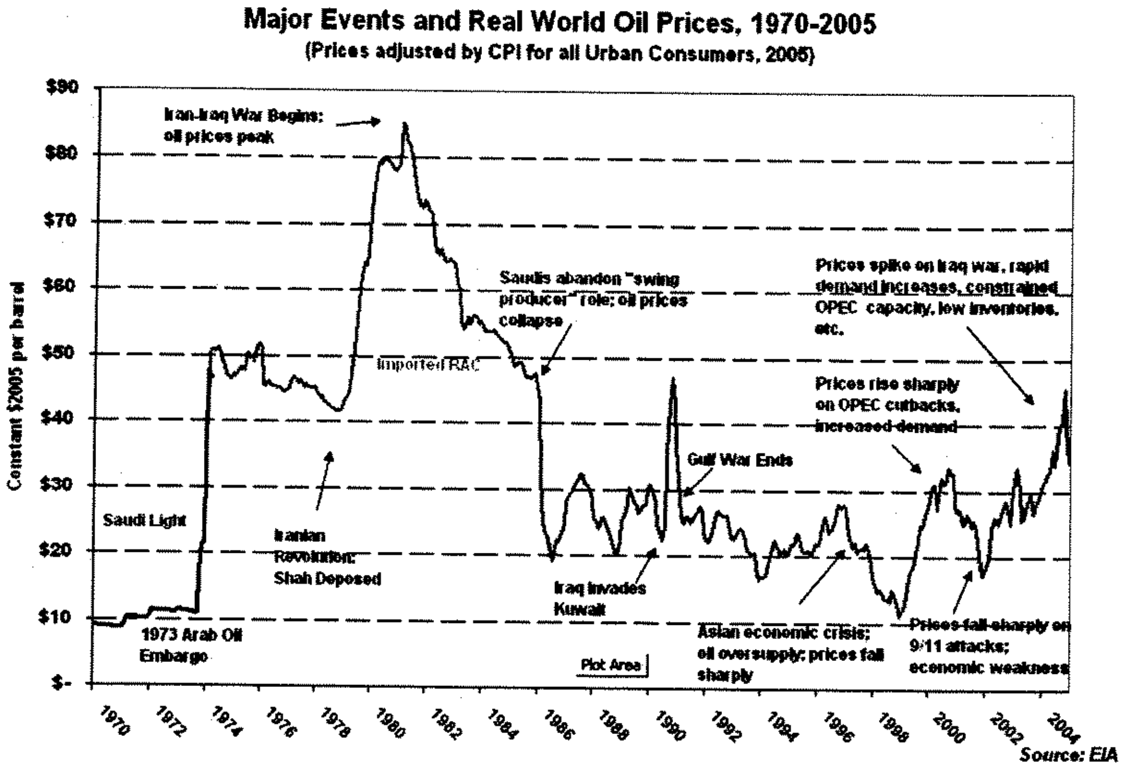
h) Office of Integrated Analysis and Forecasting
    i) Demand and Integration Division
    ii) Coal and Electric Power Division
    iii) Oil and Gas Division
    iv) International Economic and Greenhouse Gas Division

available information in a consistent method that is appropriate for the Companies' fuel oil requirements.

Fuel Oil Market Volatility and Sensitivity Scenarios

The fuel oil market is going through its most volatile condition since the Gulf War in 1990-1991 (see Figure 1).

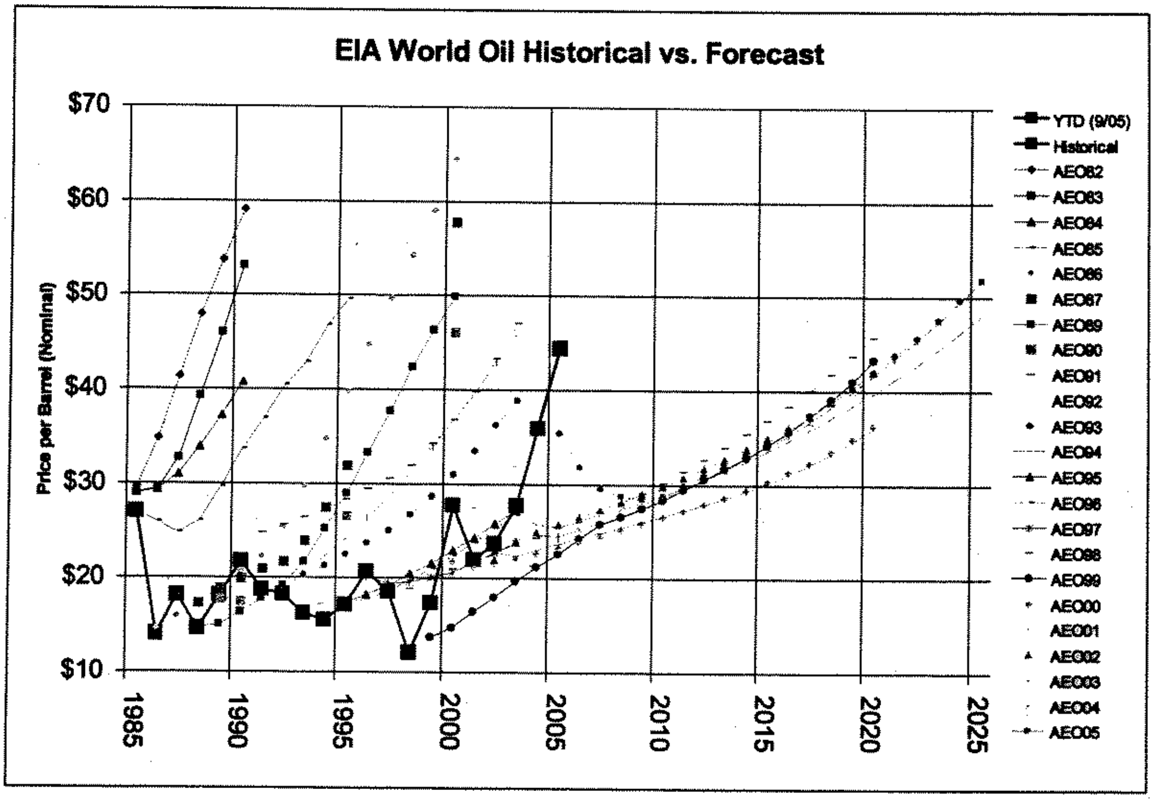
Figure 1



The economic forces that drive fuel oil prices up or down can be analyzed by examining the foundations of the supply and demand forces. While the determination of key underlying assumptions, such as future fuel prices, used in the long range planning process is clearly easier during stable market conditions, the challenge of forecasting fuel prices during volatile market conditions make it ever more important to consistently apply a methodology that derives a fundamentally sound forecast.

Prudent planning, therefore, requires taking into account past experience, and available information on the "fundamentals" underlying the "behavior" of fuel prices. It is notable that older fuel price forecasts, following fuel price spikes, tended to over forecast fuel prices. Through the '80s and into the early '90s, world oil prices were forecast by EIA to cost several times higher than the prices actually turned out to be (see Figure 2). Similarly, HECO's LSFO forecast exhibited a similar over-forecasting versus actual prices (see Figure 3).

Figure 2


EIA World Oil Historical vs. Forecast
$70
$60
$50
$40
$30
$20
$10
Price per Barrel (Nominal)
1985
1990
1995
2000
2005
2010
2015
2020
2025
YTD (9/05)
Historical
AEO82
AEO83
AEO84
AEO85
AEO86
AEO87
AEO89
AEO90
AEO91
AEO92
AEO93
AEO94
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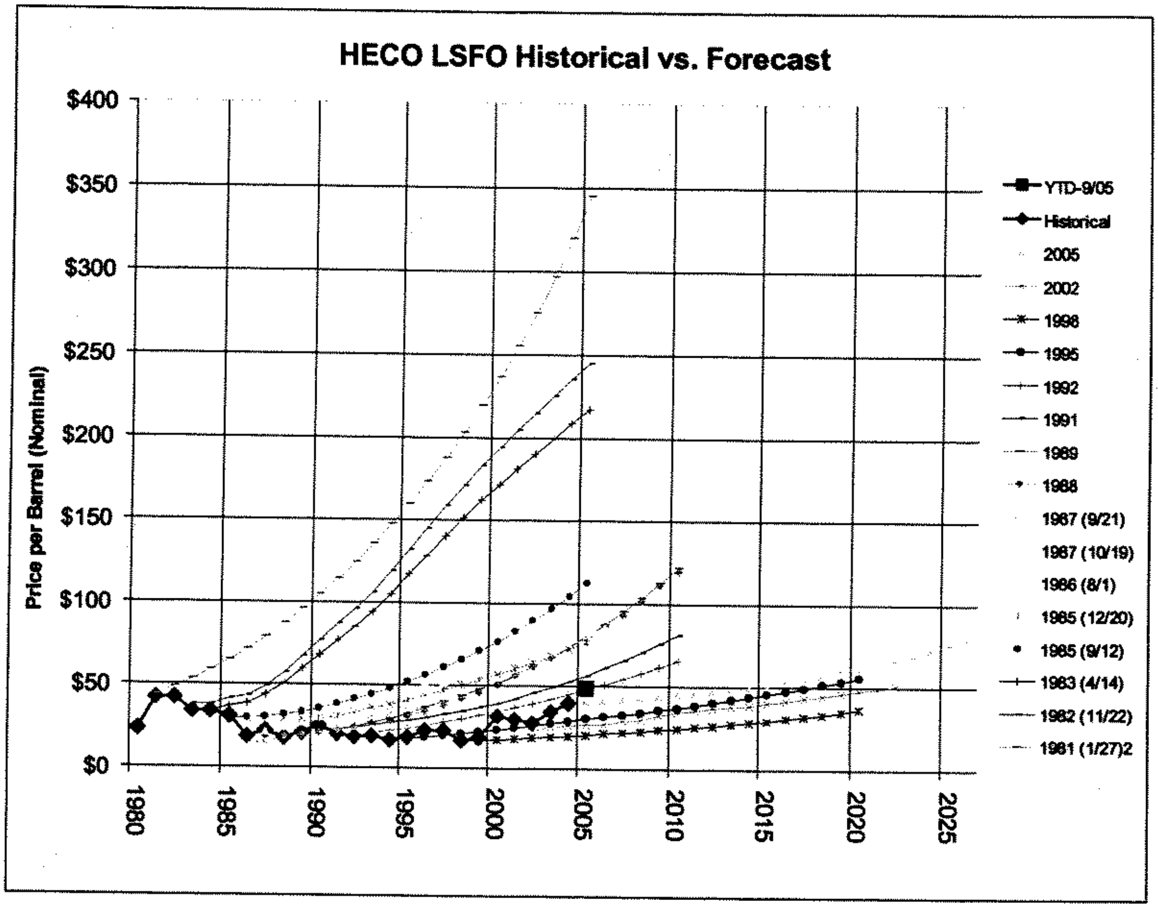
AEO05

Figure 3



More recent long-term forecasts have underestimated fuel prices in the shorter-term, while the degree to which they may deviate from actual future prices over the long-term remains to be seen. Market fundamentals, however, suggest there are points at which marginal production costs for new supply or technologies will create long-term plateaus, rather than a continuous rise in oil prices. Higher oil prices will at some point drive lower demand with associated price increase suppression.

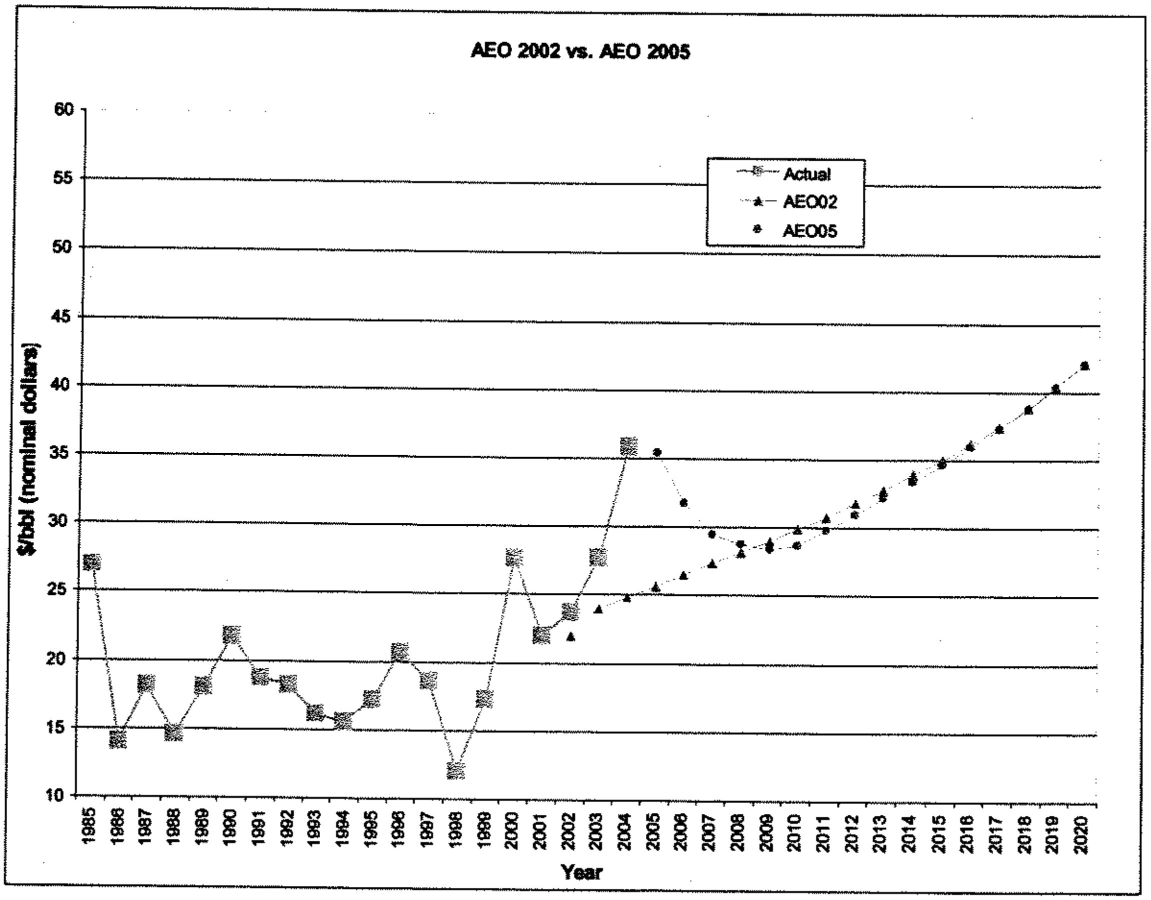
EIA recognizes that there are price constraints on ever-increasing fuel prices. In the EIA's July 2005 *IEO* report, while noting that oil prices have been highly volatile over the past 25 years, and periods of price volatility can be expected in the future principally because of unforeseen political and economic circumstances, it is recognized that market forces can play a significant role in restoring balance over an extended period. High real prices deter consumption and encourage the emergence of significant competition from large marginal sources of oil, which currently are uneconomical to produce, and other energy supplies. Persistently low prices have the opposite effects.

EIA also considered that limits to long-term oil price escalation include substitution of other fuels for oil, marginal sources of conventional oil that become reserves (i.e., economically viable) when prices rise, and non-conventional sources of oil that become reserves at still higher prices. Advances in exploration and production technologies are likely to bring prices down when such additional oil resources become part of the reserve base. EIA further discussed the view that there remains significant untapped production potential worldwide, especially in deepwater areas. Deepwater exploration and development initiatives generally are expected to be sustained worldwide, with the offshore Atlantic Basin emerging as a major future source of oil production in both Latin America and Africa.

There was also recognition that while OPEC producers are expected to be the major source of production increases to meet growing world demand through 2025, non-OPEC supply is expected to remain highly competitive, with major increments to supply coming from offshore resources, especially in the Caspian Basin, Latin America, and deepwater West Africa. EIA's estimates of incremental production are based on current proved reserves and a country-by-country assessment of ultimately recoverable petroleum. And while OPEC's share of world oil supply is projected to increase significantly over the next two decades, competitive forces are expected to remain strong enough to forestall efforts to escalate real oil prices significantly. Competitive forces operate within OPEC, between OPEC and non-OPEC sources of supply, and between conventional oil and other sources of energy (e.g. non-conventional oil, natural gas, coal, and coal gasification). Geopolitical considerations, however, will lead to potentially more cycles.

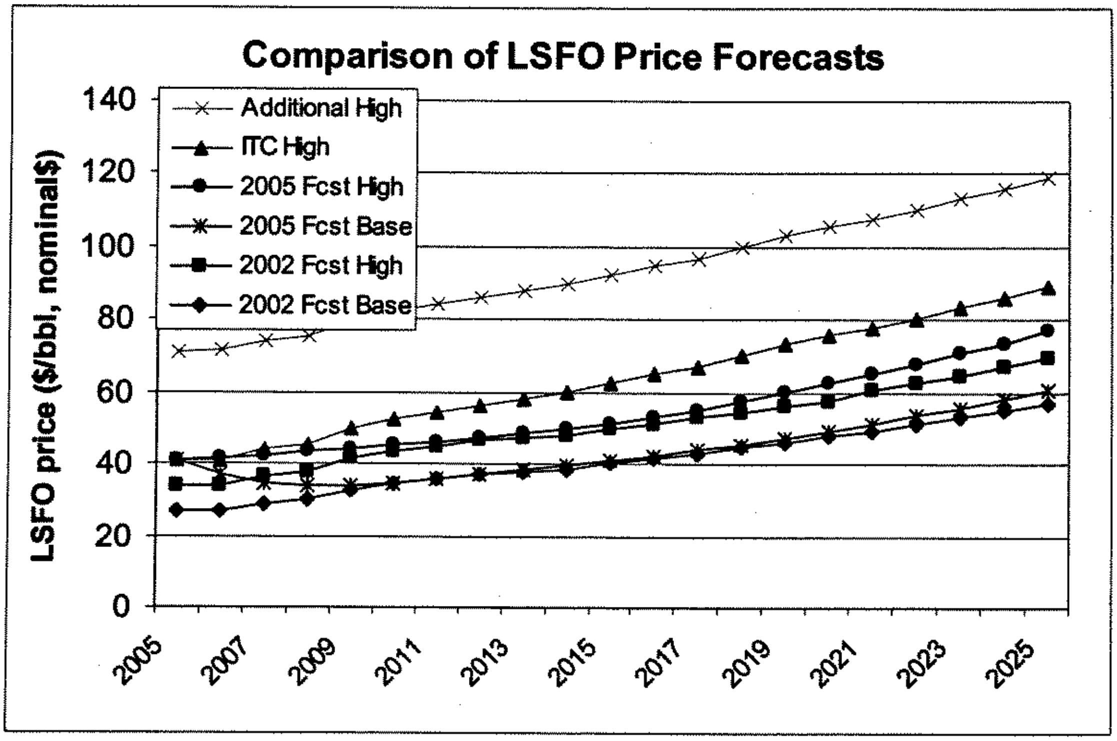
Given the cyclical experience with oil prices and likelihood of continued market volatility based on an analysis of sound fundamentals and market behavior as captured by the EIA, the Companies look to sensitivity scenarios that bracket the reasonably expected outcomes to meet the need of a 20-30 year planning period. In IRP-3, HECO used its latest long-term forecast available at the beginning of the IRP process, which included a base forecast and high and low forecasts. HECO also compared the EIA's *AEO 2002* and *AEO 2005* forecasts to determine whether its 2002 forecast used in the IRP process was too "stale" (see Figure 4). While the *AEO 2005* reference case forecast is higher than the *AEO 2002* reference case in the first several years, from 2008 and beyond they are essentially the same.

Figure 4



Another high forecast sensitivity case was developed by the IRP Integration Technical Committee. And given the most recent experience, an even higher sensitivity has been developed for the final IRP report submission, which exceeds the most recently experienced fuel prices (see Figure 5).

Figure 5



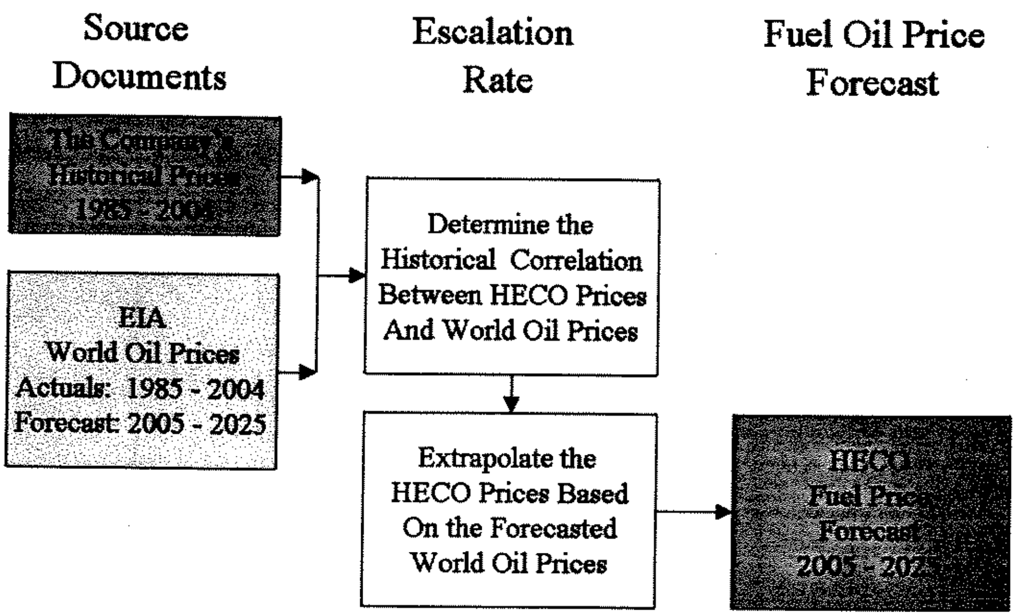
The Companies' 2005 Fuel Oil Price Forecast

The EIA market index that was utilized for the Company's fuel oil price forecast is their World Oil Price, which is the annual average U.S. refiner's acquisition cost of imported crude oil. The reason for using the World Oil Price is that it reflects the world's equilibrium price as opposed to the price of a single region. Furthermore EIA reports both the historical and forecasted data for World Oil. The other data series (e.g., West Texas Intermediate) are not publicly available for both historical and forecasted data series.

The Companies' 2005 fuel oil price forecast utilized the EIA's historical data and forecasts for World Oil Prices through statistical correlation models and trending models.

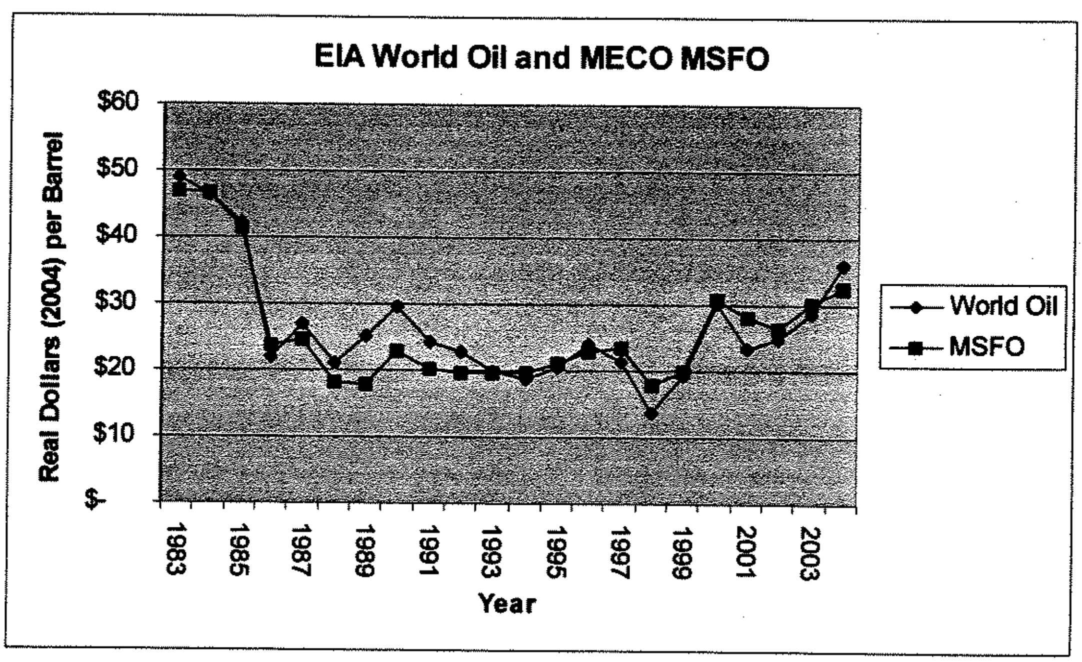
Statistical Correlation Method: The forecast methodology is to first develop a historical statistical correlation between a market index (World Oil) and the Companies' prices, then develop the Companies' fuel oil price forecast based upon the historical statistical correlation and the forecast of the market index. This process is shown in Illustration 1.

Illustration 1



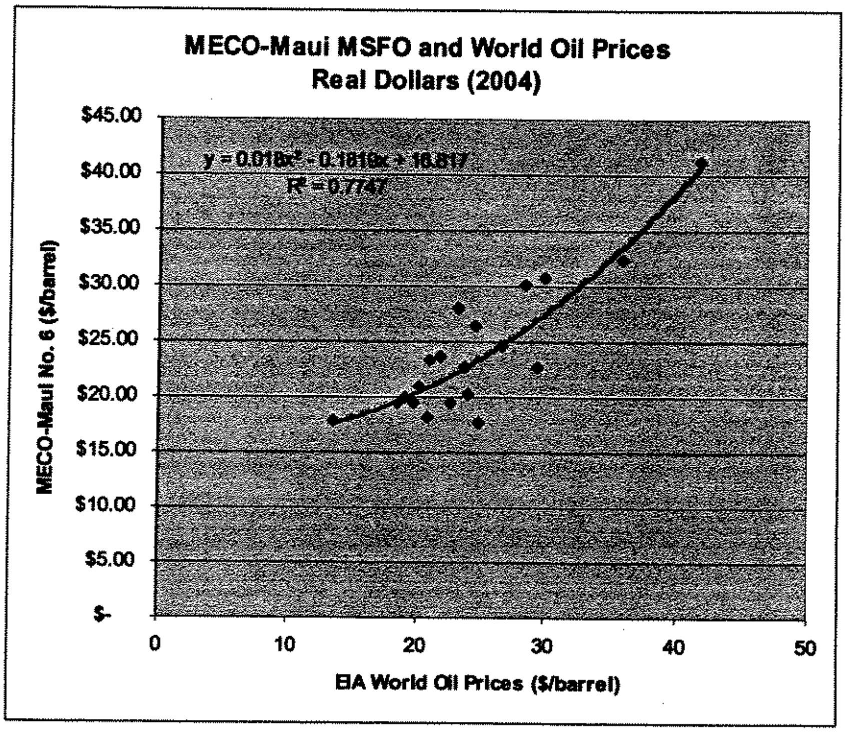
On a chronologic basis, it is clear that there is a strong statistical correlation between the World Oil price and the company's price (e.g., MECO Medium Sulfur Fuel Oil - MSFO) as shown in Figure 6.

Figure 6



In the Companies' 2005 forecast, a second order polynomial was utilized for the correlation model. It derived a better R^2 (i.e., Coefficient of Determination) for all fuel oil types that the Companies use than a linear regression model (format Y = A + BX). The second order polynomial function is shown in Figure 7.

Figure 7



Example: MECO-Maui's MSFO

Using the Second Order Polynomial function ($Y = AX^2 + BX + C$)

Where: Y = Calculated MECO Price
X = World Oil Price
A, B, & C = The Curve Fit derived coefficients

Equation: $Y = 0.018X^2 - 0.1819X + 16.817$

If: World Oil Price = $40

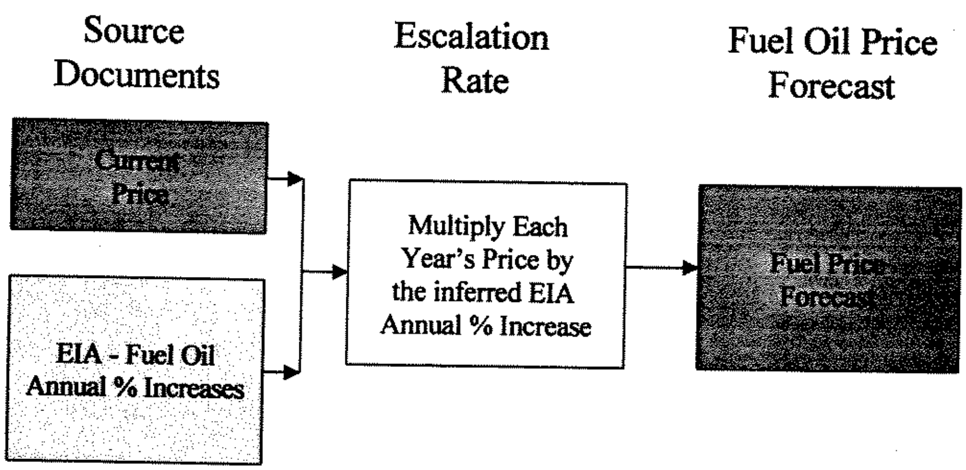
Then: MECO Price = [0.018 * ($40)^2] – [0.1819 * ($40)] + 16.817

MECO Price = $52.89 per barrel

A statistical method allows us to measure how well our forecasting model is able to use historical data to forecast our various fuel types. The R^2 measures the variance of the actual values around the forecast.[2] The R^2 for MECO-Maui MSFO is 0.7747 (high values are good).

Trending Method: The methodology for MECO's diesel oil price forecast for the island of Lanai and the Neighbor Island Coal Price Forecast used the Trending Method. The basis of the trending method is the most recent price for the fuel type. The annual escalation rates are from an EIA forecast for a similar fuel type. This process is shown in Illustration 2.

Illustration 2



The reason for using the Trending Methodology for MECO's diesel oil price forecast for Lanai is because it is purchased at a "rack price" and there is very little correlation to the World Oil Price. The reason for using the Trending Methodology for the Neighbor Island Coal Price Forecast is because of the limited historical Hawaii delivered coal price data to derive a correlation. Therefore, the trending model was the best available model given the available data. The Companies will provide the Neighbor Island Coal Price Forecast and an updated HECO Coal Price Forecast shortly upon its completion.

Statistical Correlation Coefficients and Coefficient of Determination: The statistical correlation coefficients for HECO, HELCO, and MECO are based on the historical correlation between each company's fuel oil price and EIA's World Oil price, as shown below in Table 1.

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[2] While the difference in the R^2 between the second order polynomial and the linear model is small, it was a consistent difference between all fuel oil types for the Companies. Furthermore, *if* the linear function had a stronger correlation, the curve fit model would have derived a zero value for the A coefficient.

Table 1

Statistical Correlation Model Equations and R^2s:

Company/Fuel	Model	Equation	R^2
HECO-LSFO	2nd Order Polynomial	$Y = 0.0020X^2 + 0.9339X + 5.1246$	0.8920
	Linear	$Y = 1.0444X + 3.6859$	0.8917
HECO-Diesel Oil(1)	2nd Order Polynomial	$Y = 0.0282X^2 - 0.6772X + 35.647$	0.5127
	Linear	$Y = 0.8832X + 15.399$	0.4649
HELCO-MSFO	2nd Order Polynomial	$Y = 0.0148X^2 - 0.0254X + 16.594$	0.7496
	Linear	$Y = 0.7989X + 5.8617$	0.7287
HELCO-Diesel Oil	2nd Order Polynomial	$Y = 0.0097X^2 + 0.5266X + 21.192$	0.7810
	Linear	$Y = 1.061X + 14.258$	0.7746
MECO/Maui -MSFO	2nd Order Polynomial	$Y = 0.0180X^2 - 0.1819X + 16.817$	0.7747
	Linear	$Y = 0.8173X + 3.8069$	0.7447
MECO/Maui -Diesel Oil	2nd Order Polynomial	$Y = 0.0085X^2 + 0.5510X + 19.135$	0.7813
	Linear	$Y = 1.0235X + 13.003$	0.7758
MECO/Molokai -Diesel Oil	2nd Order Polynomial	$Y = 0.0206X^2 + 0.1954X + 24.363$	0.7059
	Linear	$Y = 1.1255X + 14.243$	0.6987
MECO/Lanai -Diesel Oil(2)	2nd Order Polynomial	$Y = -0.0096X^2 + 1.1679X + 32.759$	0.3006
	Linear	$Y = 0.7315X + 37.526$	0.2990

(1) 1986's Company Price skewed the results. The company's inventory price didn't reflect the significant drop in the World Oil Prices. Exclusion of this one data point would raise the R^2 to 0.780.

(2) Lanai's Diesel Oil price is not based on a market index. Rather it is based on a rack price determined by a Hawaii refinery. The statistical model is not being used for Lanai's Diesel Oil Price Forecast.

The results of the Companies' 2005 Fuel Oil Price Forecast model are shown in Appendix A.

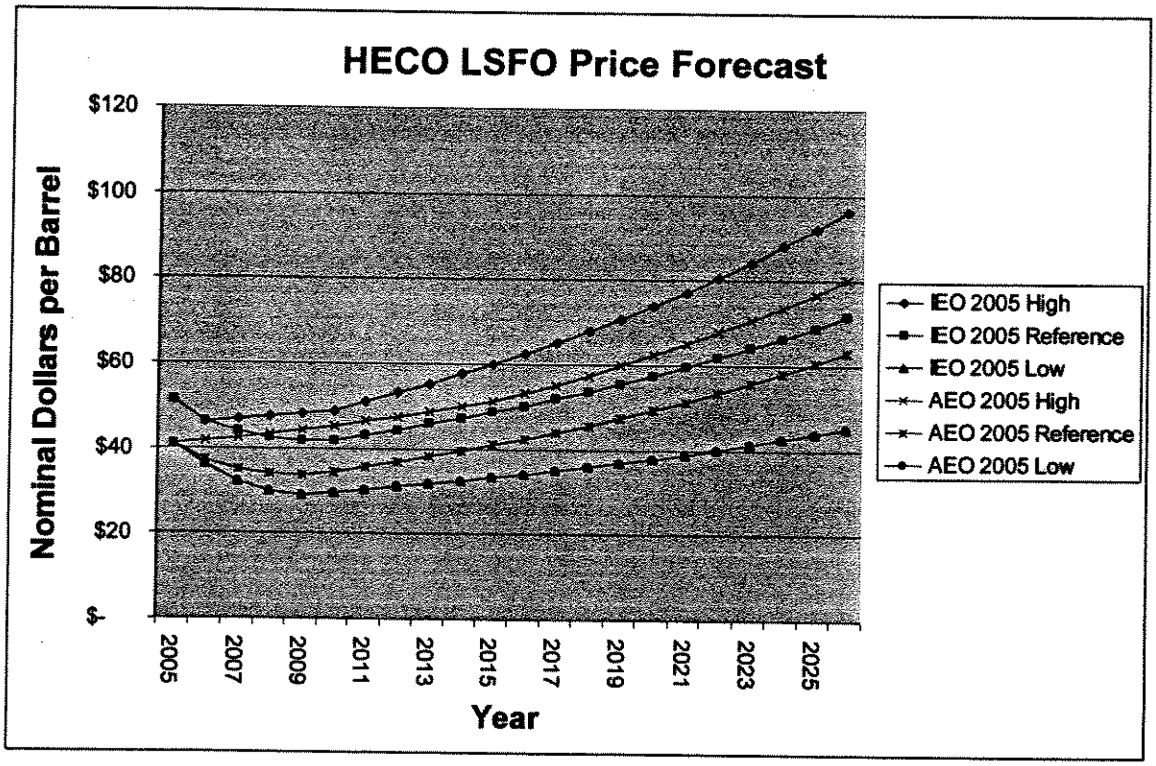
The Suggested Forecast for EI's Modeling

Due to the current volatility of the fuel oil market, for the purposes of EI's proposed modeling efforts, we suggest the use of a fuel oil price forecast based on EIA's *International Energy Outlook (IEO) 2005* report. The *IEO 2005* report was issued in July 2005, whereas the *AEO 2005* report was issued in January 2005. The EIA used an additional six months of World Oil Price historical results to refine their *AEO 2005* forecast to reflect higher World Oil Prices.

The World Oil Price forecast from the *IEO* utilized the linear model coefficients shown in Table 1 above.[3] The results of the IEO 2005 linear model are shown in Appendix B.

A comparison of the Companies' forecasts of fuel oil prices derived from the *AEO 2005* and the *IEO 2005* reports are as follows:

Figure 8



[3] The linear model is being utilized to reflect the advisory group comments received in the course of the ongoing HELCO IRP process regarding a perceived complexity of the 2nd order polynomial.

Figure 9

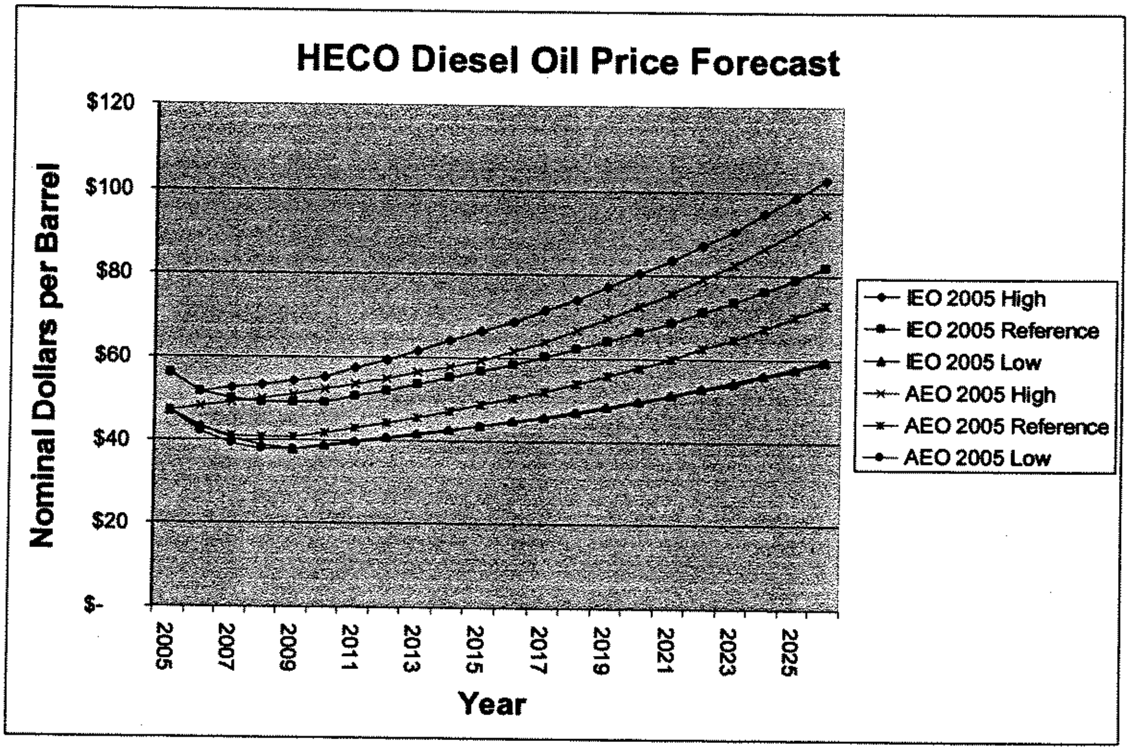


Figure 10

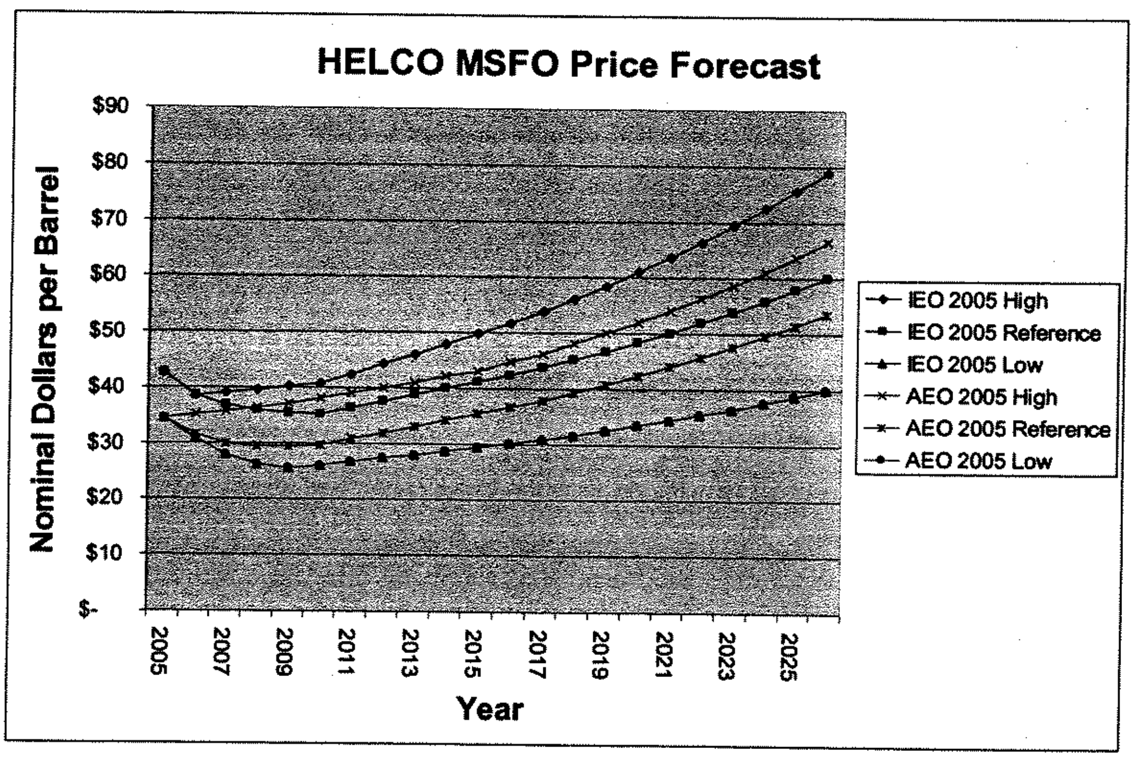


Figure 11

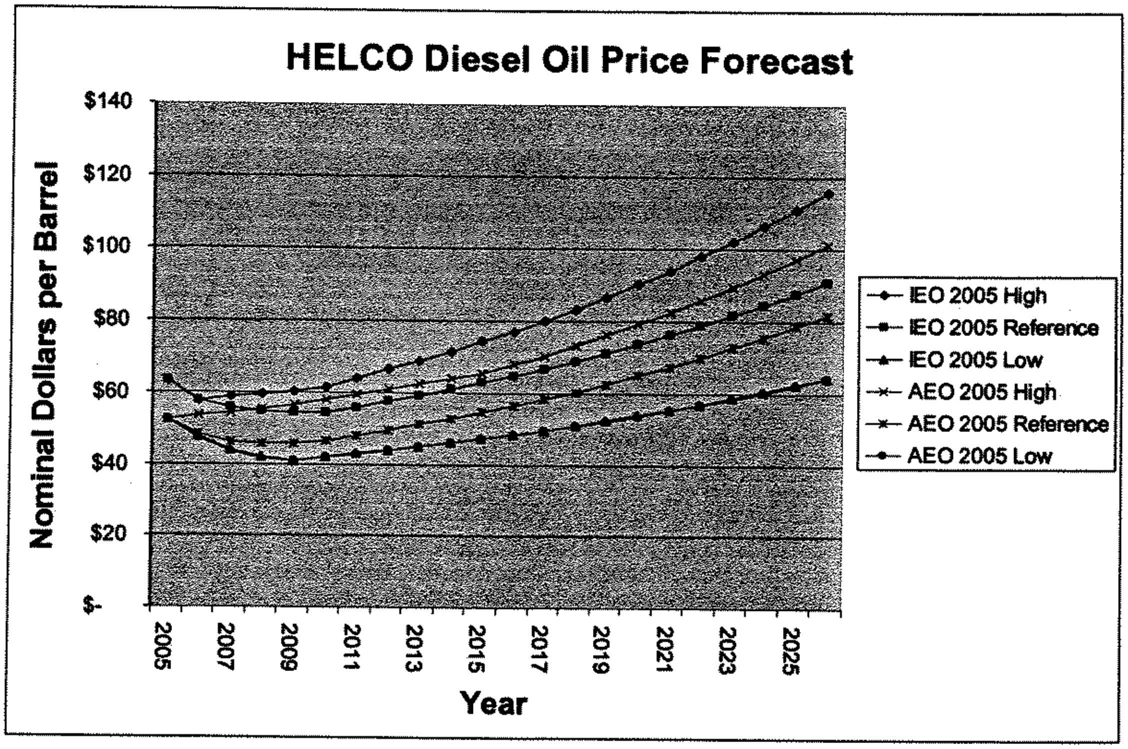


Figure 12

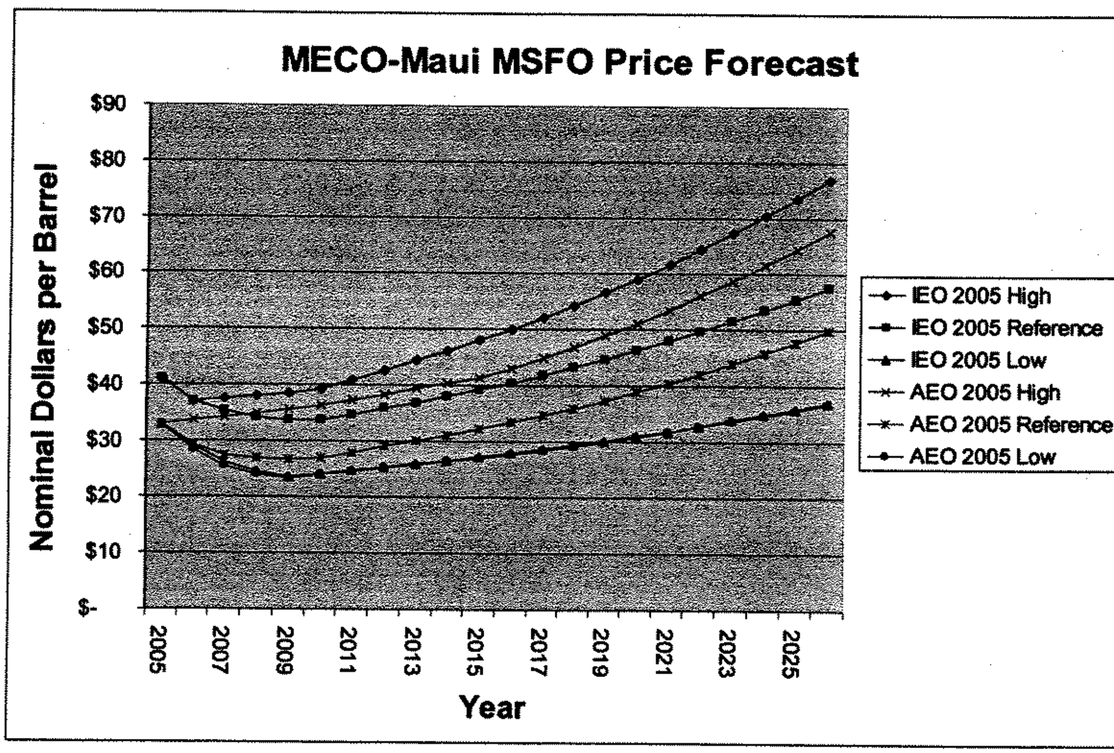


Figure 13

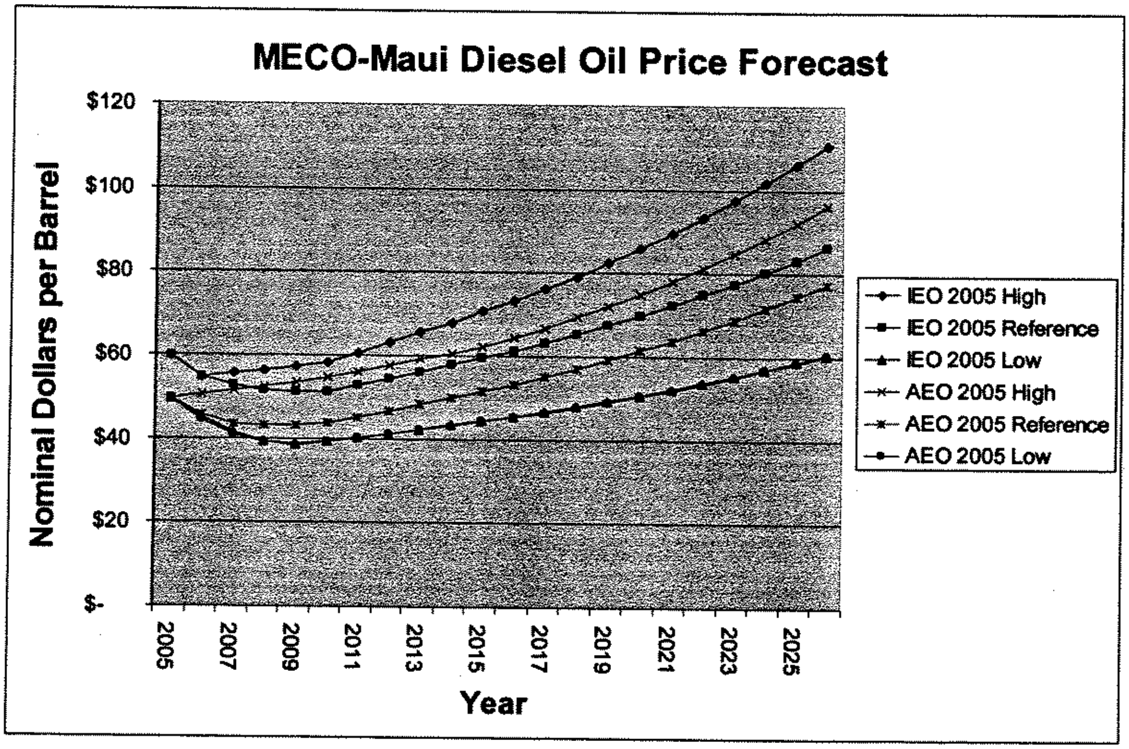


Figure 14

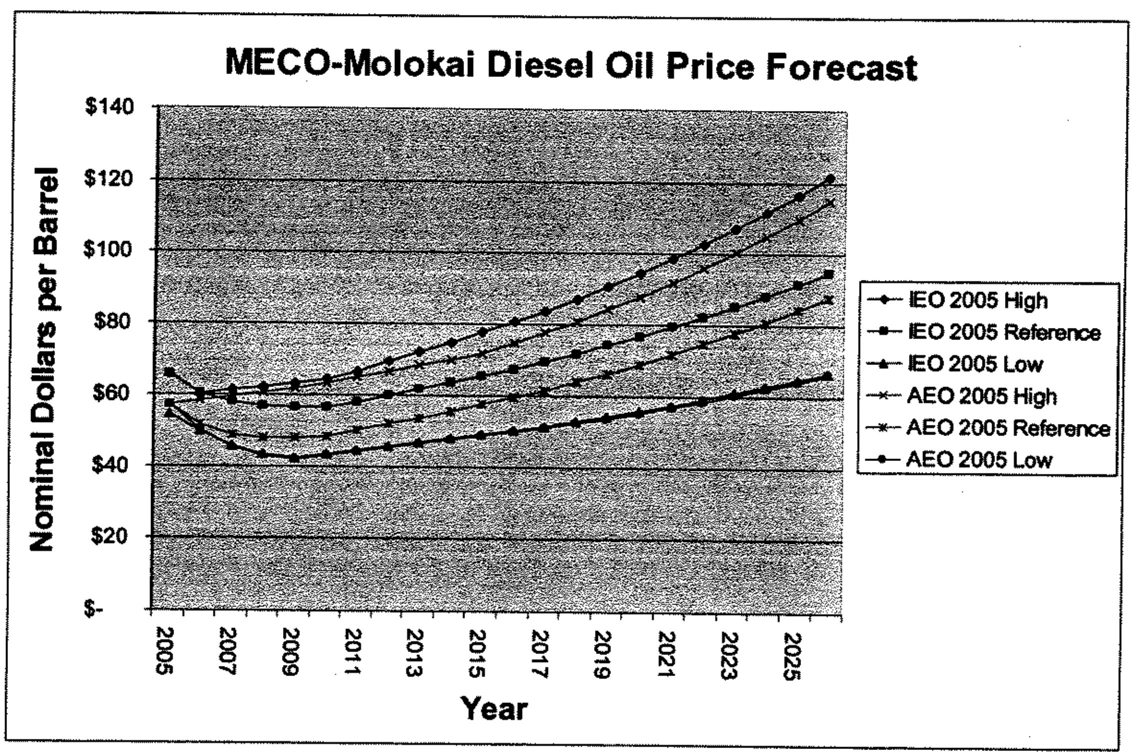
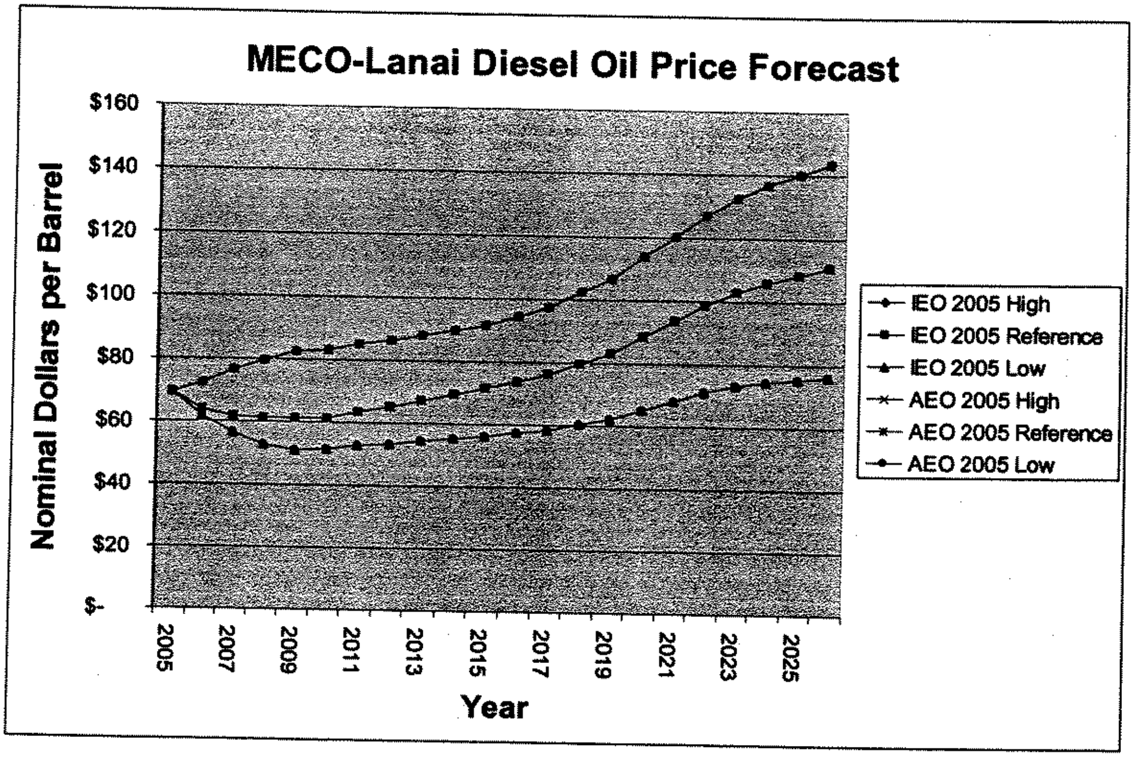


Figure 15



The Lanai diesel oil price forecast is the same for the *AEO* and the *IEO* based forecasts because the *IEO* report did not update all of the supplemental tables that provide the trending basis for the Lanai model.

The results of the *IEO 2005* based fuel oil price forecasts reflect higher fuel oil prices anticipated for all of the Companies major fuel oil types. These higher fuel oil prices are based upon fuel market fundamentals utilizing the latest publicly available information from EIA regarding the World Oil Price.

The EIA has indicated in its *IEO 2005* report issued in July that they anticipate that the *AEO 2006* report, to be issued in January 2006, may reflect even higher World Oil Prices than what was utilized in their *IEO 2005* report. The Companies will update their forecast once all necessary information (EIA's *AEO 2006* report and the Companies' fuel oil related data) is available. We anticipate its completion in February 2006.

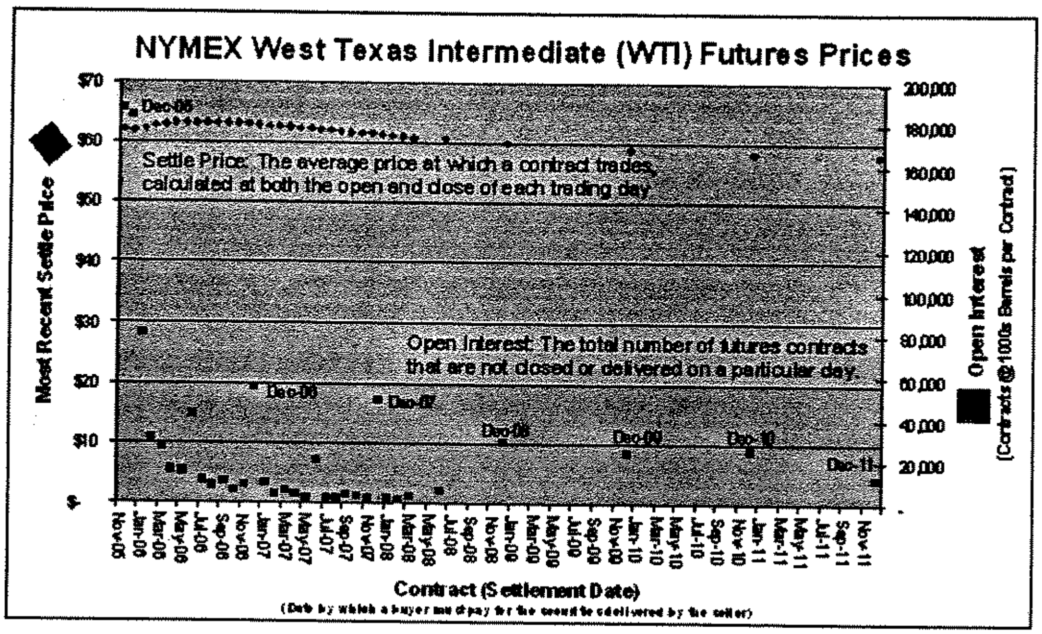
Comments on Long-term Fuel Price Forecast Methodology based on Oil Futures Market Prices

The subject of using NYMEX future as a forecast of future oil prices was discussed during the workshops. The Companies have begun reviewing the proposed use of NYMEX's Crude Oil Futures Prices as a basis for a fuel oil price forecast model as raised by other participants in the RPS workshop. Some preliminary comments follow.

NYMEX's Crude Oil Futures are long-dated futures initially listed 36, 48, 60, 72 and 84 months prior to delivery of West Texas Intermediate (WTI) which is a light, sweet crude oil. It is a futures trade of the NYMEX Crude Oil (CL) contracts, which is a WTI contracts trade of 30 consecutive months.

Of all of the energy and metals futures contracts that trade on the Exchange, less than 1% of the commodities traded are actually bought or sold through the Exchange (i.e., the majority of the transactions at the NYMEX are done for speculation purposes).[4] Thus, beyond the first two month futures window, actual trading of NYMEX Crude Oil Futures drops off dramatically as shown in Figure 16 below which is a comparison of NYMEX WTI Future Prices and Open Interest (trading volume) over the contract time.

Figure 16



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[4] The traders are grouped into Hedgers and Speculators, who have divergent goals. Hedgers do not necessarily seek to profit in the futures markets. They use the futures to help stabilize the revenues or costs of their business operations because they have an offsetting position in the physical market. A gain or loss in the futures market is usually offset to some degree by the corresponding loss or gain in the market for the underlying physical commodity. Speculators, to the contrary, do seek to profit from market movement because they do not have offsetting physical positions. However, for every speculator who tries to profit from a rising market there are those who believe they can profit in a falling market. Most speculators don't try to push the market in any direction. Instead they follow the trend, attempting to time their transactions by buying low and selling high – or first selling high and later buying back low. Note also that the protection offered to the Hedger is that they have an offsetting physical asset. If this asset is only a close substitute, the risk of the hedge is not fully mitigated, and the LSFO, MSFO, and Diesel Oil that the Companies use are not close substitute products.

In addition, as Figure 16 above shows, NYMEX Crude Oil Futures prices are highly influenced by current information and current prices that are extrapolated into the future. Thus, when current information changes, or when there is a change in sentiment in the trading community, the forecast implicit in futures prices changes accordingly.

Furthermore, the NYMEX warns all prospective traders that the Futures prices are not price predictions. This is important to consider when contemplating the appropriateness of this data as a major input to a fuel oil price forecast model. Similarly, John Conti, Energy Information Administration's Director of the Office of Integrated Analysis and Forecasting, in an informal discussion with HECO, stated that the futures market is not a good predictor of future prices. His comments parallel the NYMEX's cautionary statement on the use of a futures market as predictors of future oil prices.

The EIA, in their *AEO 2005* and *IEO 2005* reports have built an October Futures Price scenario which utilized the 30 consecutive month contract prices as only a starting point in their alternate long term price forecast scenario. The rest of the analysis was based upon their NEMS model which analyzes the interactions of price upon the supply and demand forces within all of the segments within the energy market. Finally, John Conti, EIA's Director of the Office of Integrated Analysis and Forecasting, in a recent informal discussion with the Companies, stated that the Futures Market is not a good predictor of future prices. His comments parallel the cautionary statement on the NYMEX website.

Appendix A
2005 Fuel Oil Price Forecast
Based on the AEO 2005 – Issued January 2005

2005 Fuel Oil Price Forecast
Real Dollars ($2004)

Hawaiian Electric Company

	Low Sulfur Fuel Oil (LSFO) 6.2 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 39.95	$ 39.95	$ 39.95	$ 46.12	$ 46.12	$ 46.12
2006	$ 35.61	$ 39.95	$ 34.53	$ 41.37	$ 46.12	$ 40.32
2007	$ 32.77	$ 39.95	$ 30.27	$ 38.73	$ 46.12	$ 36.74
2008	$ 31.49	$ 39.95	$ 27.63	$ 37.67	$ 46.12	$ 34.97
2009	$ 30.59	$ 39.95	$ 26.07	$ 36.97	$ 46.12	$ 34.09
2010	$ 30.27	$ 39.95	$ 26.07	$ 36.74	$ 46.12	$ 34.09
2011	$ 30.64	$ 40.01	$ 26.07	$ 37.01	$ 46.18	$ 34.09
2012	$ 31.01	$ 40.06	$ 26.07	$ 37.29	$ 46.25	$ 34.09
2013	$ 31.38	$ 40.12	$ 26.07	$ 37.58	$ 46.32	$ 34.09
2014	$ 31.75	$ 40.18	$ 26.07	$ 37.88	$ 46.39	$ 34.09
2015	$ 32.13	$ 40.23	$ 26.07	$ 38.19	$ 46.45	$ 34.09
2016	$ 32.50	$ 40.78	$ 26.07	$ 38.50	$ 47.12	$ 34.09
2017	$ 32.87	$ 41.32	$ 26.07	$ 38.82	$ 47.80	$ 34.09
2018	$ 33.24	$ 41.88	$ 26.07	$ 39.14	$ 48.50	$ 34.09
2019	$ 33.61	$ 42.43	$ 26.07	$ 39.47	$ 49.22	$ 34.09
2020	$ 34.00	$ 42.98	$ 26.07	$ 39.83	$ 49.93	$ 34.09
2021	$ 34.39	$ 43.53	$ 26.07	$ 40.18	$ 50.68	$ 34.09
2022	$ 34.77	$ 44.09	$ 26.07	$ 40.55	$ 51.44	$ 34.09
2023	$ 35.16	$ 44.65	$ 26.07	$ 40.92	$ 52.22	$ 34.09
2024	$ 35.55	$ 45.20	$ 26.07	$ 41.30	$ 52.99	$ 34.09
2025	$ 35.95	$ 45.76	$ 26.07	$ 41.70	$ 53.80	$ 34.09
2026	$ 36.35	$ 46.33	$ 26.07	$ 42.11	$ 54.62	$ 34.09

2005 Fuel Oil Price Forecast
Nominal Dollars

Hawaiian Electric Company

	Low Sulfur Fuel Oil (LSFO) 6.2 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 40.74	$ 40.74	$ 40.74	$ 47.03	$ 47.03	$ 47.03
2006	$ 36.95	$ 41.45	$ 35.82	$ 42.92	$ 47.85	$ 41.83
2007	$ 34.63	$ 42.23	$ 31.99	$ 40.94	$ 48.75	$ 38.83
2008	$ 33.95	$ 43.07	$ 29.79	$ 40.61	$ 49.71	$ 37.70
2009	$ 33.66	$ 43.97	$ 28.69	$ 40.69	$ 50.75	$ 37.52
2010	$ 34.07	$ 44.97	$ 29.34	$ 41.35	$ 51.91	$ 38.37
2011	$ 35.33	$ 46.13	$ 30.06	$ 42.68	$ 53.25	$ 39.31
2012	$ 36.64	$ 47.34	$ 30.81	$ 44.07	$ 54.65	$ 40.29
2013	$ 37.96	$ 48.55	$ 31.54	$ 45.47	$ 56.05	$ 41.25
2014	$ 39.33	$ 49.78	$ 32.30	$ 46.93	$ 57.48	$ 42.24
2015	$ 40.76	$ 51.03	$ 33.07	$ 48.45	$ 58.93	$ 43.25
2016	$ 42.19	$ 52.94	$ 33.84	$ 49.98	$ 61.17	$ 44.25
2017	$ 43.74	$ 54.99	$ 34.69	$ 51.66	$ 63.60	$ 45.36
2018	$ 45.42	$ 57.22	$ 35.62	$ 53.48	$ 66.27	$ 46.58
2019	$ 47.22	$ 59.60	$ 36.62	$ 55.45	$ 69.13	$ 47.89
2020	$ 49.11	$ 62.08	$ 37.65	$ 57.52	$ 72.12	$ 49.24
2021	$ 51.12	$ 64.73	$ 38.75	$ 59.74	$ 75.35	$ 50.68
2022	$ 53.24	$ 67.51	$ 39.91	$ 62.09	$ 78.76	$ 52.20
2023	$ 55.45	$ 70.42	$ 41.11	$ 64.54	$ 82.35	$ 53.76
2024	$ 57.78	$ 73.47	$ 42.37	$ 67.14	$ 86.14	$ 55.41
2025	$ 60.26	$ 76.71	$ 43.69	$ 69.91	$ 90.18	$ 57.14
2026	$ 62.84	$ 80.09	$ 45.06	$ 72.79	$ 94.42	$ 58.93

2005 Fuel Oil Price Forecast
Real Dollars ($2004)

Hawaii Electric Light Company

	Medium Sulfur Fuel Oil (MSFO - No. 6) 6.3 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 33.55	$ 33.55	$ 33.55	$ 51.16	$ 51.16	$ 51.16
2006	$ 29.71	$ 33.55	$ 28.82	$ 46.43	$ 51.16	$ 45.29
2007	$ 27.43	$ 33.55	$ 25.59	$ 43.47	$ 51.16	$ 40.96
2008	$ 26.47	$ 33.55	$ 23.82	$ 42.17	$ 51.16	$ 38.41
2009	$ 25.82	$ 33.55	$ 22.85	$ 41.27	$ 51.16	$ 36.94
2010	$ 25.59	$ 33.55	$ 22.85	$ 40.96	$ 51.16	$ 36.94
2011	$ 25.85	$ 33.59	$ 22.85	$ 41.32	$ 51.22	$ 36.94
2012	$ 26.12	$ 33.64	$ 22.85	$ 41.69	$ 51.28	$ 36.94
2013	$ 26.39	$ 33.71	$ 22.85	$ 42.06	$ 51.35	$ 36.94
2014	$ 26.66	$ 33.76	$ 22.85	$ 42.43	$ 51.41	$ 36.94
2015	$ 26.94	$ 33.80	$ 22.85	$ 42.82	$ 51.47	$ 36.94
2016	$ 27.22	$ 34.33	$ 22.85	$ 43.19	$ 52.09	$ 36.94
2017	$ 27.51	$ 34.85	$ 22.85	$ 43.57	$ 52.70	$ 36.94
2018	$ 27.80	$ 35.38	$ 22.85	$ 43.95	$ 53.34	$ 36.94
2019	$ 28.09	$ 35.93	$ 22.85	$ 44.34	$ 53.97	$ 36.94
2020	$ 28.39	$ 36.47	$ 22.85	$ 44.74	$ 54.60	$ 36.94
2021	$ 28.70	$ 37.03	$ 22.85	$ 45.14	$ 55.25	$ 36.94
2022	$ 29.01	$ 37.60	$ 22.85	$ 45.54	$ 55.90	$ 36.94
2023	$ 29.33	$ 38.18	$ 22.85	$ 45.95	$ 56.56	$ 36.94
2024	$ 29.65	$ 38.75	$ 22.85	$ 46.36	$ 57.21	$ 36.94
2025	$ 29.99	$ 39.35	$ 22.85	$ 46.79	$ 57.87	$ 36.94
2026	$ 30.33	$ 39.95	$ 22.85	$ 47.22	$ 58.55	$ 36.94

2005 Fuel Oil Price Forecast
Nominal Dollars

Hawaii Electric Light Company

	Medium Sulfur Fuel Oil (MSFO - No. 6) 6.3 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 34.21	$ 34.21	$ 34.21	$ 52.17	$ 52.17	$ 52.17
2006	$ 30.82	$ 34.80	$ 29.89	$ 48.17	$ 53.08	$ 46.98
2007	$ 28.99	$ 35.46	$ 27.05	$ 45.94	$ 54.07	$ 43.29
2008	$ 28.53	$ 36.16	$ 25.68	$ 45.46	$ 55.15	$ 41.40
2009	$ 28.41	$ 36.92	$ 25.15	$ 45.42	$ 56.30	$ 40.65
2010	$ 28.80	$ 37.76	$ 25.72	$ 46.10	$ 57.58	$ 41.58
2011	$ 29.81	$ 38.74	$ 26.35	$ 47.65	$ 59.06	$ 42.60
2012	$ 30.87	$ 39.76	$ 27.01	$ 49.27	$ 60.60	$ 43.66
2013	$ 31.93	$ 40.78	$ 27.65	$ 50.89	$ 62.13	$ 44.70
2014	$ 33.03	$ 41.82	$ 28.32	$ 52.57	$ 63.70	$ 45.77
2015	$ 34.18	$ 42.88	$ 28.99	$ 54.32	$ 65.29	$ 46.86
2016	$ 35.34	$ 44.56	$ 29.67	$ 56.07	$ 67.62	$ 47.95
2017	$ 36.61	$ 46.37	$ 30.41	$ 57.98	$ 70.13	$ 49.16
2018	$ 37.98	$ 48.35	$ 31.23	$ 60.06	$ 72.88	$ 50.48
2019	$ 39.45	$ 50.47	$ 32.10	$ 62.28	$ 75.82	$ 51.89
2020	$ 41.01	$ 52.68	$ 33.01	$ 64.62	$ 78.87	$ 53.36
2021	$ 42.67	$ 55.06	$ 33.98	$ 67.11	$ 82.14	$ 54.92
2022	$ 44.42	$ 57.58	$ 34.99	$ 69.73	$ 85.59	$ 56.56
2023	$ 46.26	$ 60.22	$ 36.04	$ 72.47	$ 89.20	$ 58.26
2024	$ 48.20	$ 62.99	$ 37.15	$ 75.36	$ 92.99	$ 60.05
2025	$ 50.27	$ 65.95	$ 38.31	$ 78.43	$ 97.01	$ 61.92
2026	$ 52.43	$ 69.06	$ 39.50	$ 81.62	$ 101.21	$ 63.86

2005 Fuel Oil Price Forecast
Real Dollars ($2004)

Maui Electric Company - Maui

	Medium Sulfur Fuel Oil (MSFO - No. 6) 6.3 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 32.19	$ 32.19	$ 32.19	$ 48.50	$ 48.50	$ 48.50
2006	$ 28.14	$ 32.19	$ 27.21	$ 43.99	$ 48.50	$ 42.90
2007	$ 25.78	$ 32.19	$ 23.90	$ 41.15	$ 48.50	$ 38.74
2008	$ 24.80	$ 32.19	$ 22.14	$ 39.91	$ 48.50	$ 36.28
2009	$ 24.13	$ 32.19	$ 21.19	$ 39.04	$ 48.50	$ 34.86
2010	$ 23.90	$ 32.19	$ 21.19	$ 38.74	$ 48.50	$ 34.86
2011	$ 24.17	$ 32.24	$ 21.19	$ 39.09	$ 48.56	$ 34.86
2012	$ 24.44	$ 32.30	$ 21.19	$ 39.45	$ 48.62	$ 34.86
2013	$ 24.71	$ 32.36	$ 21.19	$ 39.80	$ 48.69	$ 34.86
2014	$ 24.99	$ 32.42	$ 21.19	$ 40.16	$ 48.74	$ 34.86
2015	$ 25.28	$ 32.47	$ 21.19	$ 40.53	$ 48.80	$ 34.86
2016	$ 25.57	$ 33.03	$ 21.19	$ 40.89	$ 49.39	$ 34.86
2017	$ 25.86	$ 33.58	$ 21.19	$ 41.25	$ 49.97	$ 34.86
2018	$ 26.15	$ 34.16	$ 21.19	$ 41.62	$ 50.57	$ 34.86
2019	$ 26.45	$ 34.75	$ 21.19	$ 41.99	$ 51.18	$ 34.86
2020	$ 26.77	$ 35.33	$ 21.19	$ 42.37	$ 51.77	$ 34.86
2021	$ 27.09	$ 35.93	$ 21.19	$ 42.76	$ 52.38	$ 34.86
2022	$ 27.42	$ 36.55	$ 21.19	$ 43.14	$ 53.00	$ 34.86
2023	$ 27.75	$ 37.17	$ 21.19	$ 43.53	$ 53.62	$ 34.86
2024	$ 28.08	$ 37.79	$ 21.19	$ 43.93	$ 54.24	$ 34.86
2025	$ 28.43	$ 38.44	$ 21.19	$ 44.33	$ 54.87	$ 34.86
2026	$ 28.79	$ 39.09	$ 21.19	$ 44.75	$ 55.51	$ 34.86

2005 Fuel Oil Price Forecast
Nominal Dollars

Maui Electric Company - Maui

	Medium Sulfur Fuel Oil (MSFO - No. 6) 6.3 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 32.83	$ 32.83	$ 32.83	$ 49.46	$ 49.46	$ 49.46
2006	$ 29.19	$ 33.40	$ 28.23	$ 45.64	$ 50.32	$ 44.51
2007	$ 27.24	$ 34.02	$ 25.27	$ 43.50	$ 51.27	$ 40.95
2008	$ 26.73	$ 34.70	$ 23.86	$ 43.02	$ 52.28	$ 39.10
2009	$ 26.56	$ 35.43	$ 23.32	$ 42.97	$ 53.38	$ 38.36
2010	$ 26.90	$ 36.23	$ 23.85	$ 43.60	$ 54.59	$ 39.23
2011	$ 27.87	$ 37.18	$ 24.43	$ 45.08	$ 55.99	$ 40.19
2012	$ 28.88	$ 38.17	$ 25.04	$ 46.62	$ 57.45	$ 41.19
2013	$ 29.90	$ 39.16	$ 25.64	$ 48.16	$ 58.91	$ 42.17
2014	$ 30.96	$ 40.16	$ 26.26	$ 49.76	$ 60.39	$ 43.19
2015	$ 32.07	$ 41.19	$ 26.88	$ 51.42	$ 61.90	$ 44.22
2016	$ 33.19	$ 42.87	$ 27.51	$ 53.08	$ 64.11	$ 45.25
2017	$ 34.41	$ 44.69	$ 28.20	$ 54.90	$ 66.50	$ 46.38
2018	$ 35.74	$ 46.67	$ 28.96	$ 56.87	$ 69.10	$ 47.63
2019	$ 37.16	$ 48.81	$ 29.77	$ 58.98	$ 71.89	$ 48.96
2020	$ 38.67	$ 51.03	$ 30.61	$ 61.20	$ 74.78	$ 50.35
2021	$ 40.28	$ 53.42	$ 31.51	$ 63.57	$ 77.88	$ 51.82
2022	$ 41.98	$ 55.96	$ 32.45	$ 66.06	$ 81.15	$ 53.37
2023	$ 43.76	$ 58.63	$ 33.42	$ 68.66	$ 84.57	$ 54.97
2024	$ 45.64	$ 61.43	$ 34.44	$ 71.40	$ 88.16	$ 56.66
2025	$ 47.66	$ 64.43	$ 35.52	$ 74.32	$ 91.97	$ 58.43
2026	$ 49.77	$ 67.58	$ 36.63	$ 77.35	$ 95.95	$ 60.25

2005 Fuel Oil Price Forecast
Real Dollars ($2004)

Maui Electric Company - Molokai

Diesel Oil (0.4% Sulfur)
5.86 MBtu/Barrel

	Reference	High	Low
2005	$ 55.97	$ 55.97	$ 55.97
2006	$ 49.68	$ 55.97	$ 48.21
2007	$ 45.89	$ 55.97	$ 42.78
2008	$ 44.27	$ 55.97	$ 39.72
2009	$ 43.16	$ 55.97	$ 38.02
2010	$ 42.78	$ 55.97	$ 38.02
2011	$ 43.22	$ 56.05	$ 38.02
2012	$ 43.67	$ 56.13	$ 38.02
2013	$ 44.13	$ 56.23	$ 38.02
2014	$ 44.59	$ 56.31	$ 38.02
2015	$ 45.07	$ 56.39	$ 38.02
2016	$ 45.54	$ 57.23	$ 38.02
2017	$ 46.02	$ 58.07	$ 38.02
2018	$ 46.50	$ 58.94	$ 38.02
2019	$ 46.99	$ 59.82	$ 38.02
2020	$ 47.50	$ 60.69	$ 38.02
2021	$ 48.02	$ 61.59	$ 38.02
2022	$ 48.54	$ 62.50	$ 38.02
2023	$ 49.06	$ 63.42	$ 38.02
2024	$ 49.59	$ 64.33	$ 38.02
2025	$ 50.15	$ 65.28	$ 38.02
2026	$ 50.71	$ 66.24	$ 38.02

Maui Electric Company - Lanai

Diesel Oil (0.4% Sulfur)
5.86 MBtu/Barrel

	Reference	High	Low
2005	$ 67.54	$ 67.54	$ 67.54
2006	$ 61.06	$ 69.18	$ 59.01
2007	$ 58.09	$ 72.20	$ 53.10
2008	$ 56.39	$ 73.30	$ 48.51
2009	$ 55.41	$ 74.45	$ 45.98
2010	$ 53.93	$ 73.33	$ 45.29
2011	$ 54.67	$ 73.42	$ 45.28
2012	$ 54.86	$ 72.77	$ 44.82
2013	$ 55.29	$ 72.49	$ 44.57
2014	$ 55.59	$ 72.03	$ 44.22
2015	$ 56.08	$ 71.79	$ 44.02
2016	$ 56.50	$ 72.45	$ 43.77
2017	$ 56.87	$ 73.02	$ 43.50
2018	$ 58.00	$ 74.60	$ 43.82
2019	$ 58.79	$ 75.73	$ 43.86
2020	$ 60.98	$ 78.60	$ 44.92
2021	$ 62.58	$ 80.75	$ 45.53
2022	$ 64.07	$ 82.77	$ 46.04
2023	$ 64.98	$ 84.02	$ 46.12
2024	$ 64.89	$ 83.97	$ 45.50
2025	$ 64.47	$ 83.47	$ 44.65
2026	$ 64.05	$ 82.97	$ 43.82

2005 Fuel Oil Price Forecast
Nominal Dollars

Maui Electric Company - Molokai

Diesel Oil (0.4% Sulfur)
5.86 MBtu/Barrel

	Reference	High	Low
2005	$ 57.08	$ 57.08	$ 57.08
2006	$ 51.54	$ 58.06	$ 50.01
2007	$ 48.50	$ 59.15	$ 45.21
2008	$ 47.72	$ 60.33	$ 42.82
2009	$ 47.50	$ 61.59	$ 41.84
2010	$ 48.15	$ 62.99	$ 42.79
2011	$ 49.84	$ 64.63	$ 43.84
2012	$ 51.61	$ 66.33	$ 44.93
2013	$ 53.39	$ 68.03	$ 46.00
2014	$ 55.25	$ 69.77	$ 47.11
2015	$ 57.18	$ 71.53	$ 48.23
2016	$ 59.12	$ 74.30	$ 49.36
2017	$ 61.24	$ 77.28	$ 50.60
2018	$ 63.54	$ 80.54	$ 51.95
2019	$ 66.01	$ 84.03	$ 53.41
2020	$ 68.61	$ 87.66	$ 54.92
2021	$ 71.39	$ 91.57	$ 56.53
2022	$ 74.31	$ 95.70	$ 58.22
2023	$ 77.38	$ 100.03	$ 59.96
2024	$ 80.61	$ 104.57	$ 61.80
2025	$ 84.06	$ 109.42	$ 63.73
2026	$ 87.66	$ 114.50	$ 65.73

Maui Electric Company - Lanai

Diesel Oil (0.4% Sulfur)
5.86 MBtu/Barrel

	Reference	High	Low
2005	$ 68.87	$ 68.87	$ 68.87
2006	$ 63.35	$ 71.78	$ 61.22
2007	$ 61.39	$ 76.31	$ 56.12
2008	$ 60.79	$ 79.02	$ 52.29
2009	$ 60.98	$ 81.93	$ 50.60
2010	$ 60.70	$ 82.53	$ 50.97
2011	$ 63.03	$ 84.65	$ 52.21
2012	$ 64.83	$ 86.00	$ 52.97
2013	$ 66.89	$ 87.71	$ 53.93
2014	$ 68.87	$ 89.24	$ 54.79
2015	$ 71.14	$ 91.08	$ 55.84
2016	$ 73.34	$ 94.05	$ 56.82
2017	$ 75.68	$ 97.17	$ 57.89
2018	$ 79.26	$ 101.93	$ 59.87
2019	$ 82.58	$ 106.37	$ 61.61
2020	$ 88.08	$ 113.54	$ 64.88
2021	$ 93.04	$ 120.06	$ 67.69
2022	$ 98.11	$ 126.73	$ 70.49
2023	$ 102.48	$ 132.52	$ 72.74
2024	$ 105.48	$ 136.48	$ 73.97
2025	$ 108.07	$ 139.91	$ 74.85
2026	$ 110.72	$ 143.43	$ 75.75

2005 Fuel Oil Price Forecast

Neighbor Island Delivered Coal Price

	Real Dollars (2004)			Nominal Dollars		
	short ton	metric tonne	MMBTU	short ton	metric tonne	MMBTU
2005	$ 72.42	$ 79.83	$ 3.05	$ 73.90	$ 81.45	$ 3.11
2006	$ 71.74	$ 79.08	$ 3.02	$ 74.46	$ 82.07	$ 3.13
2007	$ 70.81	$ 78.05	$ 2.98	$ 74.87	$ 82.53	$ 3.15
2008	$ 70.69	$ 77.92	$ 2.98	$ 76.24	$ 84.04	$ 3.21
2009	$ 70.53	$ 77.75	$ 2.97	$ 77.64	$ 85.58	$ 3.27
2010	$ 68.85	$ 75.89	$ 2.90	$ 77.50	$ 85.43	$ 3.26
2011	$ 67.17	$ 74.04	$ 2.83	$ 77.47	$ 85.40	$ 3.26
2012	$ 66.29	$ 73.07	$ 2.79	$ 78.36	$ 86.38	$ 3.30
2013	$ 65.73	$ 72.45	$ 2.77	$ 79.58	$ 87.72	$ 3.35
2014	$ 65.59	$ 72.30	$ 2.76	$ 81.29	$ 89.60	$ 3.42
2015	$ 65.54	$ 72.24	$ 2.76	$ 83.16	$ 91.67	$ 3.50
2016	$ 65.36	$ 72.05	$ 2.75	$ 84.87	$ 93.56	$ 3.57
2017	$ 65.24	$ 71.91	$ 2.75	$ 86.82	$ 95.71	$ 3.65
2018	$ 65.33	$ 72.01	$ 2.75	$ 89.30	$ 98.43	$ 3.76
2019	$ 65.38	$ 72.07	$ 2.75	$ 91.84	$ 101.24	$ 3.87
2020	$ 65.19	$ 71.85	$ 2.74	$ 94.16	$ 103.80	$ 3.96
2021	$ 63.66	$ 70.17	$ 2.68	$ 94.67	$ 104.35	$ 3.98
2022	$ 63.07	$ 69.52	$ 2.65	$ 96.58	$ 106.46	$ 4.07
2023	$ 63.12	$ 69.57	$ 2.66	$ 99.58	$ 109.76	$ 4.19
2024	$ 63.21	$ 69.67	$ 2.66	$ 102.75	$ 113.26	$ 4.32
2025	$ 63.19	$ 69.65	$ 2.66	$ 105.94	$ 116.77	$ 4.46
2026	$ 63.17	$ 69.63	$ 2.66	$ 109.22	$ 120.39	$ 4.60

Appendix B

2005 Alternate Price Scenario
Based on the IEO 2005 – Issued July 2005

2005 Alternate Price Scenario - IEO 2005
Real Dollars ($2004)

Hawaiian Electric Company

	Low Sulfur Fuel Oil (LSFO) 6.2 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 50.22	$ 50.22	$ 39.95	$ 54.75	$ 54.75	$ 46.06
2006	$ 44.19	$ 44.19	$ 34.62	$ 49.65	$ 49.65	$ 41.55
2007	$ 41.28	$ 43.95	$ 30.35	$ 47.19	$ 49.45	$ 37.95
2008	$ 39.15	$ 43.68	$ 27.68	$ 45.39	$ 49.22	$ 35.69
2009	$ 37.81	$ 43.41	$ 26.08	$ 44.26	$ 49.00	$ 34.34
2010	$ 36.75	$ 43.15	$ 26.08	$ 43.36	$ 48.77	$ 34.34
2011	$ 37.04	$ 43.93	$ 26.08	$ 43.60	$ 49.43	$ 34.34
2012	$ 37.31	$ 44.72	$ 26.08	$ 43.84	$ 50.10	$ 34.34
2013	$ 37.60	$ 45.49	$ 26.08	$ 44.08	$ 50.75	$ 34.34
2014	$ 37.89	$ 46.27	$ 26.08	$ 44.32	$ 51.41	$ 34.34
2015	$ 38.17	$ 47.06	$ 26.08	$ 44.56	$ 52.08	$ 34.34
2016	$ 38.45	$ 47.84	$ 26.08	$ 44.80	$ 52.74	$ 34.34
2017	$ 38.74	$ 48.62	$ 26.08	$ 45.05	$ 53.40	$ 34.34
2018	$ 39.02	$ 49.41	$ 26.08	$ 45.28	$ 54.06	$ 34.34
2019	$ 39.31	$ 50.19	$ 26.08	$ 45.52	$ 54.72	$ 34.34
2020	$ 39.60	$ 50.98	$ 26.08	$ 45.77	$ 55.39	$ 34.34
2021	$ 39.87	$ 51.75	$ 26.08	$ 46.00	$ 56.05	$ 34.34
2022	$ 40.16	$ 52.53	$ 26.08	$ 46.24	$ 56.71	$ 34.34
2023	$ 40.44	$ 53.32	$ 26.08	$ 46.48	$ 57.37	$ 34.34
2024	$ 40.73	$ 54.10	$ 26.08	$ 46.72	$ 58.03	$ 34.34
2025	$ 41.01	$ 54.88	$ 26.08	$ 46.97	$ 58.69	$ 34.34
2026	$ 41.30	$ 55.67	$ 26.08	$ 47.21	$ 59.36	$ 34.34

2005 Alternate Price Scenario - IEO 2005
Nominal Dollars

Hawaiian Electric Company

	Low Sulfur Fuel Oil (LSFO) 6.2 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 51.21	$ 51.21	$ 40.73	$ 55.83	$ 55.83	$ 46.97
2006	$ 45.84	$ 45.84	$ 35.91	$ 51.51	$ 51.51	$ 43.11
2007	$ 43.63	$ 46.44	$ 32.07	$ 49.87	$ 52.26	$ 40.10
2008	$ 42.19	$ 47.08	$ 29.84	$ 48.92	$ 53.05	$ 38.47
2009	$ 41.61	$ 47.77	$ 28.70	$ 48.70	$ 53.91	$ 37.78
2010	$ 41.36	$ 48.56	$ 29.35	$ 48.79	$ 54.88	$ 38.64
2011	$ 42.70	$ 50.64	$ 30.07	$ 50.27	$ 56.99	$ 39.59
2012	$ 44.09	$ 52.84	$ 30.82	$ 51.80	$ 59.20	$ 40.58
2013	$ 45.49	$ 55.04	$ 31.56	$ 53.33	$ 61.40	$ 41.54
2014	$ 46.94	$ 57.33	$ 32.31	$ 54.91	$ 63.70	$ 42.54
2015	$ 48.41	$ 59.69	$ 33.08	$ 56.52	$ 66.06	$ 43.56
2016	$ 49.91	$ 62.10	$ 33.86	$ 58.15	$ 68.45	$ 44.57
2017	$ 51.55	$ 64.69	$ 34.70	$ 59.93	$ 71.05	$ 45.69
2018	$ 53.31	$ 67.50	$ 35.64	$ 61.86	$ 73.86	$ 46.92
2019	$ 55.21	$ 70.49	$ 36.63	$ 63.94	$ 76.86	$ 48.23
2020	$ 57.19	$ 73.62	$ 37.67	$ 66.10	$ 80.00	$ 49.59
2021	$ 59.28	$ 76.94	$ 38.77	$ 68.38	$ 83.32	$ 51.05
2022	$ 61.48	$ 80.43	$ 39.93	$ 70.80	$ 86.82	$ 52.57
2023	$ 63.77	$ 84.09	$ 41.13	$ 73.29	$ 90.47	$ 54.15
2024	$ 66.19	$ 87.93	$ 42.39	$ 75.94	$ 94.32	$ 55.81
2025	$ 68.74	$ 91.98	$ 43.72	$ 78.72	$ 98.37	$ 57.55
2026	$ 71.39	$ 96.22	$ 45.08	$ 81.60	$ 102.60	$ 59.35

2005 Alternate Price Scenario - IEO 2005
Real Dollars ($2004)

Hawaii Electric Light Company

	Medium Sulfur Fuel Oil (MSFO - No. 6) 6.3 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 41.46	$ 41.46	$ 33.60	$ 61.53	$ 61.53	$ 51.10
2006	$ 36.85	$ 36.85	$ 29.52	$ 55.41	$ 55.41	$ 45.68
2007	$ 34.62	$ 36.66	$ 26.26	$ 52.45	$ 55.16	$ 41.35
2008	$ 32.99	$ 36.46	$ 24.22	$ 50.28	$ 54.89	$ 38.64
2009	$ 31.97	$ 36.25	$ 22.99	$ 48.93	$ 54.62	$ 37.01
2010	$ 31.15	$ 36.05	$ 22.99	$ 47.85	$ 54.35	$ 37.01
2011	$ 31.37	$ 36.64	$ 22.99	$ 48.14	$ 55.14	$ 37.01
2012	$ 31.58	$ 37.25	$ 22.99	$ 48.42	$ 55.94	$ 37.01
2013	$ 31.81	$ 37.84	$ 22.99	$ 48.71	$ 56.73	$ 37.01
2014	$ 32.03	$ 38.44	$ 22.99	$ 49.01	$ 57.52	$ 37.01
2015	$ 32.24	$ 39.04	$ 22.99	$ 49.29	$ 58.32	$ 37.01
2016	$ 32.46	$ 39.64	$ 22.99	$ 49.58	$ 59.11	$ 37.01
2017	$ 32.68	$ 40.23	$ 22.99	$ 49.87	$ 59.91	$ 37.01
2018	$ 32.89	$ 40.84	$ 22.99	$ 50.15	$ 60.71	$ 37.01
2019	$ 33.11	$ 41.43	$ 22.99	$ 50.45	$ 61.50	$ 37.01
2020	$ 33.33	$ 42.04	$ 22.99	$ 50.74	$ 62.30	$ 37.01
2021	$ 33.54	$ 42.63	$ 22.99	$ 51.02	$ 63.09	$ 37.01
2022	$ 33.76	$ 43.23	$ 22.99	$ 51.31	$ 63.88	$ 37.01
2023	$ 33.98	$ 43.83	$ 22.99	$ 51.59	$ 64.68	$ 37.01
2024	$ 34.20	$ 44.43	$ 22.99	$ 51.89	$ 65.47	$ 37.01
2025	$ 34.42	$ 45.02	$ 22.99	$ 52.18	$ 66.27	$ 37.01
2026	$ 34.64	$ 45.63	$ 22.99	$ 52.47	$ 67.07	$ 37.01

2005 Alternate Price Scenario - IEO 2005
Nominal Dollars

Hawaii Electric Light Company

	Medium Sulfur Fuel Oil (MSFO - No. 6) 6.3 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 42.27	$ 42.27	$ 34.26	$ 62.74	$ 62.74	$ 52.10
2006	$ 38.22	$ 38.22	$ 30.62	$ 57.48	$ 57.48	$ 47.38
2007	$ 36.59	$ 38.74	$ 27.75	$ 55.43	$ 58.29	$ 43.69
2008	$ 35.56	$ 39.29	$ 26.10	$ 54.20	$ 59.16	$ 41.64
2009	$ 35.18	$ 39.89	$ 25.30	$ 53.84	$ 60.10	$ 40.72
2010	$ 35.06	$ 40.57	$ 25.88	$ 53.84	$ 61.16	$ 41.65
2011	$ 36.17	$ 42.25	$ 26.51	$ 55.50	$ 63.57	$ 42.67
2012	$ 37.32	$ 44.01	$ 27.17	$ 57.22	$ 66.10	$ 43.73
2013	$ 38.48	$ 45.78	$ 27.82	$ 58.93	$ 68.63	$ 44.78
2014	$ 39.68	$ 47.62	$ 28.49	$ 60.71	$ 71.26	$ 45.85
2015	$ 40.89	$ 49.52	$ 29.17	$ 62.52	$ 73.98	$ 46.95
2016	$ 42.13	$ 51.45	$ 29.85	$ 64.35	$ 76.73	$ 48.04
2017	$ 43.48	$ 53.53	$ 30.59	$ 66.36	$ 79.71	$ 49.25
2018	$ 44.94	$ 55.79	$ 31.42	$ 68.52	$ 82.94	$ 50.57
2019	$ 46.50	$ 58.19	$ 32.30	$ 70.85	$ 86.38	$ 51.98
2020	$ 48.14	$ 60.71	$ 33.21	$ 73.28	$ 89.98	$ 53.45
2021	$ 49.86	$ 63.37	$ 34.18	$ 75.85	$ 93.79	$ 55.02
2022	$ 51.69	$ 66.18	$ 35.20	$ 78.56	$ 97.80	$ 56.66
2023	$ 53.58	$ 69.12	$ 36.26	$ 81.36	$ 102.00	$ 58.36
2024	$ 55.58	$ 72.20	$ 37.37	$ 84.33	$ 106.41	$ 60.15
2025	$ 57.68	$ 75.46	$ 38.54	$ 87.46	$ 111.07	$ 62.03
2026	$ 59.87	$ 78.86	$ 39.74	$ 90.70	$ 115.92	$ 63.97

2005 Alternate Price Scenario - IEO 2005
Real Dollars ($2004)

Maui Electric Company - Maui

	Medium Sulfur Fuel Oil (MSFO - No. 6) 6.3 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 40.22	$ 40.22	$ 32.18	$ 58.60	$ 58.60	$ 48.54
2006	$ 35.51	$ 35.51	$ 28.01	$ 52.70	$ 52.70	$ 43.31
2007	$ 33.23	$ 35.31	$ 24.67	$ 49.85	$ 52.46	$ 39.13
2008	$ 31.56	$ 35.11	$ 22.59	$ 47.76	$ 52.20	$ 36.52
2009	$ 30.51	$ 34.90	$ 21.33	$ 46.45	$ 51.94	$ 34.95
2010	$ 29.68	$ 34.69	$ 21.33	$ 45.40	$ 51.68	$ 34.95
2011	$ 29.91	$ 35.30	$ 21.33	$ 45.69	$ 52.44	$ 34.95
2012	$ 30.12	$ 35.91	$ 21.33	$ 45.96	$ 53.21	$ 34.95
2013	$ 30.35	$ 36.52	$ 21.33	$ 46.24	$ 53.97	$ 34.95
2014	$ 30.57	$ 37.13	$ 21.33	$ 46.52	$ 54.74	$ 34.95
2015	$ 30.79	$ 37.75	$ 21.33	$ 46.79	$ 55.51	$ 34.95
2016	$ 31.02	$ 38.36	$ 21.33	$ 47.08	$ 56.27	$ 34.95
2017	$ 31.24	$ 38.97	$ 21.33	$ 47.36	$ 57.04	$ 34.95
2018	$ 31.46	$ 39.59	$ 21.33	$ 47.63	$ 57.81	$ 34.95
2019	$ 31.68	$ 40.20	$ 21.33	$ 47.91	$ 58.57	$ 34.95
2020	$ 31.91	$ 40.81	$ 21.33	$ 48.19	$ 59.35	$ 34.95
2021	$ 32.13	$ 41.42	$ 21.33	$ 48.47	$ 60.11	$ 34.95
2022	$ 32.35	$ 42.03	$ 21.33	$ 48.75	$ 60.87	$ 34.95
2023	$ 32.57	$ 42.65	$ 21.33	$ 49.02	$ 61.65	$ 34.95
2024	$ 32.79	$ 43.26	$ 21.33	$ 49.30	$ 62.41	$ 34.95
2025	$ 33.02	$ 43.87	$ 21.33	$ 49.58	$ 63.17	$ 34.95
2026	$ 33.25	$ 44.49	$ 21.33	$ 49.87	$ 63.94	$ 34.95

2005 Alternate Price Scenario - IEO 2005
Nominal Dollars

Maui Electric Company - Maui

	Medium Sulfur Fuel Oil (MSFO - No. 6) 6.3 MBtu/Barrel			Diesel Oil (0.4% Sulfur) 5.86 MBtu/Barrel		
	Reference	High	Low	Reference	High	Low
2005	$ 41.01	$ 41.01	$ 32.82	$ 59.76	$ 59.76	$ 49.50
2006	$ 36.83	$ 36.83	$ 29.06	$ 54.67	$ 54.67	$ 44.93
2007	$ 35.11	$ 37.32	$ 26.07	$ 52.68	$ 55.44	$ 41.36
2008	$ 34.01	$ 37.84	$ 24.34	$ 51.47	$ 56.26	$ 39.36
2009	$ 33.58	$ 38.40	$ 23.47	$ 51.11	$ 57.15	$ 38.46
2010	$ 33.40	$ 39.04	$ 24.01	$ 51.10	$ 58.15	$ 39.33
2011	$ 34.48	$ 40.69	$ 24.60	$ 52.67	$ 60.46	$ 40.30
2012	$ 35.59	$ 42.44	$ 25.21	$ 54.31	$ 62.88	$ 41.30
2013	$ 36.71	$ 44.19	$ 25.81	$ 55.94	$ 65.30	$ 42.28
2014	$ 37.88	$ 46.01	$ 26.43	$ 57.64	$ 67.82	$ 43.30
2015	$ 39.06	$ 47.88	$ 27.06	$ 59.36	$ 70.41	$ 44.33
2016	$ 40.26	$ 49.79	$ 27.69	$ 61.10	$ 73.04	$ 45.37
2017	$ 41.57	$ 51.85	$ 28.39	$ 63.01	$ 75.89	$ 46.51
2018	$ 42.98	$ 54.09	$ 29.15	$ 65.07	$ 78.98	$ 47.75
2019	$ 44.50	$ 56.46	$ 29.96	$ 67.29	$ 82.27	$ 49.09
2020	$ 46.08	$ 58.95	$ 30.81	$ 69.61	$ 85.71	$ 50.48
2021	$ 47.76	$ 61.58	$ 31.71	$ 72.05	$ 89.36	$ 51.96
2022	$ 49.53	$ 64.35	$ 32.66	$ 74.63	$ 93.19	$ 53.51
2023	$ 51.36	$ 67.26	$ 33.64	$ 77.30	$ 97.21	$ 55.12
2024	$ 53.30	$ 70.31	$ 34.67	$ 80.13	$ 101.43	$ 56.81
2025	$ 55.34	$ 73.53	$ 35.76	$ 83.11	$ 105.88	$ 58.58
2026	$ 57.46	$ 76.89	$ 36.88	$ 86.20	$ 110.53	$ 60.41

2005 Alternate Price Scenario - IEO 2005
Real Dollars ($2004)

Maui Electric Company - Molokai

Diesel Oil (0.4% Sulfur)
5.86 MBtu/Barrel

	Reference	High	Low
2005	$ 64.39	$ 64.39	$ 53.32
2006	$ 57.90	$ 57.90	$ 47.57
2007	$ 54.76	$ 57.63	$ 42.98
2008	$ 52.46	$ 57.34	$ 40.10
2009	$ 51.02	$ 57.06	$ 38.38
2010	$ 49.87	$ 56.77	$ 38.38
2011	$ 50.18	$ 57.61	$ 38.38
2012	$ 50.48	$ 58.46	$ 38.38
2013	$ 50.79	$ 59.30	$ 38.38
2014	$ 51.10	$ 60.14	$ 38.38
2015	$ 51.40	$ 60.99	$ 38.38
2016	$ 51.71	$ 61.83	$ 38.38
2017	$ 52.02	$ 62.67	$ 38.38
2018	$ 52.32	$ 63.52	$ 38.38
2019	$ 52.63	$ 64.35	$ 38.38
2020	$ 52.94	$ 65.21	$ 38.38
2021	$ 53.24	$ 66.04	$ 38.38
2022	$ 53.55	$ 66.88	$ 38.38
2023	$ 53.85	$ 67.73	$ 38.38
2024	$ 54.16	$ 68.57	$ 38.38
2025	$ 54.47	$ 69.41	$ 38.38
2026	$ 54.78	$ 70.26	$ 38.38

Maui Electric Company - Lanai

Diesel Oil (0.4% Sulfur)
5.86 MBtu/Barrel

	Reference	High	Low
2005	$ 67.54	$ 67.54	$ 67.54
2006	$ 61.06	$ 69.18	$ 59.01
2007	$ 58.09	$ 72.20	$ 53.10
2008	$ 56.39	$ 73.30	$ 48.51
2009	$ 55.41	$ 74.45	$ 45.98
2010	$ 53.93	$ 73.33	$ 45.29
2011	$ 54.67	$ 73.42	$ 45.28
2012	$ 54.86	$ 72.77	$ 44.82
2013	$ 55.29	$ 72.49	$ 44.57
2014	$ 55.59	$ 72.03	$ 44.22
2015	$ 56.08	$ 71.79	$ 44.02
2016	$ 56.50	$ 72.45	$ 43.77
2017	$ 56.87	$ 73.02	$ 43.50
2018	$ 58.00	$ 74.60	$ 43.82
2019	$ 58.79	$ 75.73	$ 43.86
2020	$ 60.98	$ 78.60	$ 44.92
2021	$ 62.58	$ 80.75	$ 45.53
2022	$ 64.07	$ 82.77	$ 46.04
2023	$ 64.98	$ 84.02	$ 46.12
2024	$ 64.89	$ 83.97	$ 45.50
2025	$ 64.47	$ 83.47	$ 44.65
2026	$ 64.05	$ 82.97	$ 43.82

2005 Alternate Price Scenario - IEO 2005
Nominal Dollars

Maui Electric Company - Molokai

Diesel Oil (0.4% Sulfur)
5.86 MBtu/Barrel

	Reference	High	Low
2005	$ 65.66	$ 65.66	$ 54.37
2006	$ 60.06	$ 60.06	$ 49.35
2007	$ 57.87	$ 60.90	$ 45.42
2008	$ 56.54	$ 61.81	$ 43.22
2009	$ 56.14	$ 62.78	$ 42.23
2010	$ 56.12	$ 63.89	$ 43.19
2011	$ 57.86	$ 66.42	$ 44.25
2012	$ 59.65	$ 69.08	$ 45.35
2013	$ 61.45	$ 71.74	$ 46.43
2014	$ 63.31	$ 74.50	$ 47.55
2015	$ 65.20	$ 77.36	$ 48.68
2016	$ 67.12	$ 80.25	$ 49.82
2017	$ 69.22	$ 83.38	$ 51.07
2018	$ 71.48	$ 86.78	$ 52.44
2019	$ 73.92	$ 90.39	$ 53.90
2020	$ 76.46	$ 94.17	$ 55.43
2021	$ 79.15	$ 98.18	$ 57.05
2022	$ 81.98	$ 102.39	$ 58.76
2023	$ 84.92	$ 106.81	$ 60.52
2024	$ 88.02	$ 111.45	$ 62.38
2025	$ 91.30	$ 116.34	$ 64.33
2026	$ 94.69	$ 121.44	$ 66.34

Maui Electric Company - Lanai

Diesel Oil (0.4% Sulfur)
5.86 MBtu/Barrel

	Reference	High	Low
2005	$ 68.87	$ 68.87	$ 68.87
2006	$ 63.35	$ 71.78	$ 61.22
2007	$ 61.39	$ 76.31	$ 56.12
2008	$ 60.79	$ 79.02	$ 52.29
2009	$ 60.98	$ 81.93	$ 50.60
2010	$ 60.70	$ 82.53	$ 50.97
2011	$ 63.03	$ 84.65	$ 52.21
2012	$ 64.83	$ 86.00	$ 52.97
2013	$ 66.89	$ 87.71	$ 53.93
2014	$ 68.87	$ 89.24	$ 54.79
2015	$ 71.14	$ 91.08	$ 55.84
2016	$ 73.34	$ 94.05	$ 56.82
2017	$ 75.68	$ 97.17	$ 57.89
2018	$ 79.26	$ 101.93	$ 59.87
2019	$ 82.58	$ 106.37	$ 61.61
2020	$ 88.08	$ 113.54	$ 64.88
2021	$ 93.04	$ 120.06	$ 67.69
2022	$ 98.11	$ 126.73	$ 70.49
2023	$ 102.48	$ 132.52	$ 72.74
2024	$ 105.48	$ 136.48	$ 73.97
2025	$ 108.07	$ 139.91	$ 74.85
2026	$ 110.72	$ 143.43	$ 75.75